Supreme Court, U.S.
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No. 02-

IN THE

Supreme Court of the United States

INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA, *et al.*,

Petitioners,

v.

REBECCA WATSON, ASSISTANT SECRETARY FOR LAND AND MINERALS MANAGEMENT, DOI, AND UNITED STATES DEPARTMENT OF THE INTERIOR,

Respondents.

ON PETITION FOR A WRIT OF CERTIORARI TO THE UNITED STATES COURT OF APPEALS FOR THE DISTRICT OF COLUMBIA CIRCUIT

PETITION FOR A WRIT OF CERTIORARI

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QUESTIONS PRESENTED

1. Whether the United States, having agreed in oil and natural gas lease contracts (as required by governing statutes) that lease royalty payments are limited to the value of oil and gas on the lands where they are produced, may issue regulations requiring lessees to pay royalties on values the United States acknowledges are higher than values at those leases.

2. Whether the Secretary of the Interior's interpretation of the lease contracts was governed by principles of contract law under *Mobil Oil Exploration and Producing Southeast, Inc. v. United States*, 530 U.S. 604 (2000), and *United States v. Seckinger*, 397 U.S. 203 (1970), and not by deferential standards of review under *Chevron U.S.A., Inc. v. Natural Resources Defense Council, Inc.*, 467 U.S. 837 (1984).

PARTIES TO PROCEEDING BELOW AND RULE 29.6 STATEMENT

The following parties were plaintiffs-appellees in the court of appeals: Independent Petroleum Association of America and American Petroleum Institute.

The named parties defendants before the district court were Robert L. Armstrong, Assistant Secretary for Land and Minerals Management at the United States Department of the Interior and the United States Department of the Interior. As Mr. Armstrong was sued in his official capacity and no longer serves as the Assistant Secretary, the Acting Assistant Secretary Wallace P. DeWitt was substituted as the named appellant at the time of the appeal. Rebecca Watson is the new Assistant Secretary and has therefore been substituted as named Respondent, along with the United States Department of the Interior, before this Court. *See* S. Ct. R. 35(3).

Pursuant to Rule 29.6, Independent Petroleum Association of America and American Petroleum Institute state that each is a non-profit corporation having no parent companies, subsidiaries, or affiliates that have issued shares or debt securities to the public.

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Petitioners Independent Petroleum Association of America ("IPAA") and American Petroleum Institute ("API") (collectively "the Associations") respectfully petition for a writ of certiorari to review the judgment of the United States Court of Appeals for the District of Columbia Circuit in this case.

OPINIONS BELOW

The opinion of the United States District Court for the District of Columbia granting petitioners' motions for summary judgment was entered on March 28, 2000, and is reported at 91 F. Supp. 2d 117 (D.D.C. 2000). (App. 20a.) The district court amended its decision on September 6, 2000. (App.17a.) The opinion of the United States Court of Appeals for the District of Columbia Circuit reversing in part the judgment of the district court was entered on February 8, 2002, and is reported at 279 F.3d 1036 (D.C. Cir. 2002). (App. 1a.) The court of appeals denied the Associations' petitions for rehearing and suggestion for rehearing *en banc* on June 21, 2002. (App. 49a, 51a.)

STATEMENT OF JURISDICTION

The court of appeals entered its decision on February 8, 2002. On March 25, 2002, petitioners timely filed petitions for rehearing and suggestion for rehearing *en banc*. The court denied the petitions on June 21, 2002. This Court has jurisdiction under 28 U.S.C. § 1254(1) (2000).

STATUTES AND REGULATORY PROVISIONS INVOLVED

The statutes involved in this case are (1) the Mineral Leasing Act, ch. 85, 41 Stat. 437 (codified as amended at 30 U.S.C. §§ 181-287 (2000)), (2) the Mineral Leasing Act for Acquired Lands, ch. 513, 61 Stat. 913 (codified as amended at 30 U.S.C. §§ 351-360 (2000)), (3) Indian Leasing Statutes (tribal leases) ch. 198, 52 Stat. 347& ch. 808, 70 Stat. 774 (codified at 25 U.S.C. §§ 396a-396g (2000)); Indian Leasing Statutes (allotted leases) ch. 263, 35 Stat. 783 (codified at 25 U.S.C. § 396 (2000)), and (4) the Outer Continental Shelf Lands Act of 1953, ch. 345, 67 Stat. 462 (codified as amended at 43 U.S.C. §§ 1331-1356

(2000)), which are reproduced in pertinent part in the appendix at 53a-62a, 63a-64a, 65a-67a, and 68a-80a, respectively.

The regulations involved in this case are (1) the 1997 regulations of the United States Department of the Interior ("Department") governing deductions those lessees may take from their proceeds of sale when they ship natural gas for sale at a point beyond the leased lands, *see, e.g.*, 30 C.F.R. §§ 206.152(i) & 206.153(i) (1999), and (2) the 1988 gas valuation regulations of the Department which first codified the practice of taking deductions for the cost of transporting gas to a downstream point of sale, *see* 30 C.F.R. §§ 206.152, 206.153, 206.156 & 206.157 (1994), which are reproduced in pertinent part in the appendix at 81a-92a & 93a-129a, respectively.

STATEMENT OF THE CASE

In oil and gas lease contracts it drafts, the Department of the Interior agrees to accept royalty payments from its lessees based on the value of natural gas at the lease, the defining standard for royalty value set by statute. This case presents the questions of whether the Department can (1) incorporate into those contracts a new regulation admittedly increasing the value to a level above the value at the lease and (2) have its action reviewed by the courts under the deferential principles of *Chevron U.S.A., Inc. v. Natural Resources Defense Council, Inc.*, 467 U.S. 837 (1984). Under the longstanding precept that "[t]he United States does business on business terms[,]" *United States v. Nat'l Exch. Bank of Baltimore*, 270 U.S. 527, 534 (1926), this Court held two terms ago, in a case involving some of the same contract forms, that "[w]hen the United States enters into contract relations, its rights and duties therein are governed generally by the law applicable to contracts between private individuals." *Mobil Oil Exploration & Producing Southeast, Inc. v. United States*, 530 U.S. 604, 607 (2000) ("*Mobil Oil*") (quoting *United States v. Winstar Corp.*, 518 U.S. 839, 895 (1996) (plurality opinion) (internal quotation marks omitted)). In conflict with *Mobil Oil*, the decision below declines to apply contract law principles to determine whether the new regulations

are consistent with the contracts. Instead, holding that "the federal government is not your standard oil-and-gas lessor" (App. 2a), the decision below effectively allows the United States do business on government terms, not business terms.

The decision accords deference to the agency's interpretation of regulations incorporated into the contracts, in conflict with decisions of the First, Fourth, Fifth, and Federal Circuits — and with earlier decisions of the District of Columbia Circuit itself — which have ruled that courts do not defer to agency interpretations of contracts. Indeed, at least the Federal Circuit has found that deference is not owed to an agency's interpretation of regulations incorporated into contracts. *See, e.g., S. Cal. Edison Co. v. United States*, 226 F.3d 1349, 1357 (Fed. Cir. 2000) ("When a party enters into a contract with the government, that party should reasonably expect to be on equal legal footing with the government should a dispute over the contract arise.").

By deferring to the Department's unilateral reconstruction of the basic contract bargain through regulation, the decision below calls into question the reliability of that bargain in approximately 25,000 currently producing oil and gas leases administered by the Department, and an additional 35,000 yet-to-produce leases, on which this Nation's energy security depends. Left uncorrected, the decision invites any federal agency to flout contract commitments through regulation.

1. *Overview of the Dispute*

The Associations sue on behalf of their members holding oil and gas leases issued or approved by the Department and enforced by its Minerals Management Service ("MMS"). The Associations challenge the Department's 1997 regulations categorically limiting deductions those lessees may take from their proceeds of sale to determine value for royalty purposes when they ship natural gas for sale at a point beyond the leased lands. (App. 81a-92a.) The regulations help the Department value its "royalty," the share it has reserved in the oil and gas the lessee produces. When a lessee enhances the value of natural gas by processing it or selling it at a location nearer the ultimate

consumer, "allowances are generally required for the value added to the gas after production." *Xeno, Inc.*, 134 IBLA 172, 180 (1995). The 1997 regulations, however, distinguish value added by costs deemed to be "transportation" from value added by costs deemed to be "marketing" away from, or "downstream" of, the leased lands, and categorically deny deductions for those downstream marketing costs. (L-11-L-23.) The Department based this distinction on what it believed to be a duty of its lessees implied in all lease contracts, to market oil and gas without cost to the lessor. (T-14.)

The district court found no basis for this allegedly implied duty: "[E]ndorsing MMS' interpretation of the leases and regulations would place no logical limits on MMS' authority to rewrite the leases to the detriment of the lessees and the direct pecuniary benefit of the government." (App. 47a.) Without disagreeing with the district court's analysis of the lease contracts on this point, the court of appeals reversed the district court in part, giving *Chevron* deference to the Department's distinction between marketing and transportation. (App. 7a-11a.)

2. *Overview of Natural Gas Markets*

Fundamental to this dispute is the distinction between markets for natural gas at the lease locations at which the gas is produced and markets located downstream of these lease markets. Department precedent explained that

> the reality of the economics of natural gas production and distribution . . . [is that t]here may be several markets between the producer of the raw natural resources and the end user. The closer the production is to the end user, the more valuable it is. . . . [T]he natural gas distribution network is often a chain of markets with increasing value at each point until the product reaches the end user.

(L-62.) "Moving gas away from the wellhead to downstream markets," the district court elaborated below, "entails costs that are not incurred when gas is marketed at the lease. Thus, from

an economic standpoint, the higher sale prices obtained in a downstream market are, in part, a reflection of the costs and risks involved." (App. 24a.)

3. *The Governing Statutes and the Department's Lease Contracts Value Royalties at the Lease*

Because natural gas may flow through several markets between the wellhead and the ultimate consumer, the question of how the government's royalty share is to be valued is determined in part by *where* it is to be valued. The answer to that question is a valuable part of the rights the lessee receives to explore for, develop, and produce oil and gas resources. To obtain those rights, lessees agree to pay not only rents and royalties "in amount or value" of the oil or gas produced, but also "bonuses" to obtain the leases, up-front payments that can be sizeable. *See Mobil Oil*, 530 U.S. at 611 ($156 million in bonuses for leases off North Carolina).

The leases reserve to the government the option to take its royalty "in value," *i.e.*, as a percent of the dollar value of the gas produced from the lease, or "in kind," *i.e.*, as a percent of the actual gas produced from the lease. *See, e.g.*, 30 U.S.C. § 226(c)(1) (2000). When the government takes its royalty in value, the lease contracts and governing statutes, as they have historically been construed, have mandated that the value of production on which royalty is due is the value of the production at the lease. This construction is reflected in numerous Departmental and judicial precedents,[1] was conceded by the

1. *Cal. Co. v. Udall*, 296 F.2d 384, 387 (D.C. Cir. 1961) (the value for royalty purposes is the value of production "in the field within a short distance of the wells"); *Marathon Oil Co. v. United States*, 604 F. Supp. 1375, 1384-85 (D. Alaska 1985), *aff'd*, 807 F.2d 759 (9th Cir. 1986); *United States v. Gen. Petroleum Corp.*, 73 F. Supp. 225, 235 (S.D. Cal. 1946), *aff'd sub nom., Cont'l Oil Co. v. United States*, 184 F.2d 802, 820 (9th Cir. 1950); *Xeno, Inc.*, 134 IBLA 172, 180 (1995) ("[A]llowances are generally required for the value added to the gas after production."); *Mobil Producing Texas & New Mexico, Inc.*, 115 IBLA 164, 172 (1990) (same); *see also, e.g.*, 30 C.F.R. § 206.151 (1999) (defining the term "net-back method"); 30 C.F.R. § 206.171 (1999) ("net-back" method of valuation serves "to ascertain value at the lease.").

government in its briefs below, and was acknowledged by both the district court (App. 36a) and the court of appeals. (App. 2a.) When the government takes its royalty "in kind", the lessee's obligation is to deliver the production without cost to the lessor "on" (in most form contracts) or "on or immediately adjacent to" (in others) "the leased area." (*E.g.*, L-37 & L-29). The Department has never contended, until this case, that it has a right to a higher value when taking its royalty in value than when taking its royalty in kind. On the contrary, it has admitted, "[r]oyalty based on value of [production] at the lease is the economic equivalent of the value of the royalty [in kind]." *Petro-Lewis Corp.*, 108 IBLA 20, 42 n.8 (1989).

Consistent with the principle of valuing production at the lease, the Department at the earliest stage of its oil and gas leasing programs acknowledged that it must deduct from the sales value of liquid natural gasoline the costs incurred to manufacture it, because the

> value of this product is contingent upon the value of the raw material and the cost of its manufacture. The Government does not wish to collect royalty on that part of the value which is derived from the cost of manufacturing, inasmuch as the Government's equity is confined to the value of the raw material involved.

52 Pub. Lands Dec. 1, 11 (1926). The Department also granted additional deductions for natural gas processing in the Rocky Mountain area because "climatic and economic conditions" created "unusually high operating and *marketing costs*." *Id.* at 12 (emphasis added). Federal and Indian lessees have also been allowed to deduct the costs of transporting natural gas away from the lease from which it was produced. *See Gen. Petroleum*, 73 F. Supp. at 257; 53 Fed. Reg. 1230, 1257 (Jan. 15, 1988) (codifying lessees' right to deduct transportation costs when selling gas away from the lease "to calculate the value of production at the lease").

In addition to deductions for the costs of manufacturing, processing, and transportation, the Department has authorized deductions for "liquefaction" — the cooling of gaseous methane to condense it into liquid before transoceanic shipment — and for electrical generation when oil was used to fuel electrical generators. *Marathon*, 604 F. Supp. at 1385; *Petro-Lewis Corp.*, 108 IBLA 20, 36 (1989). The animating principle behind these seemingly disparate deductions is that deductions generally are allowed for any costs which "further enhance [the lease production's] value . . . ." *Petro-Lewis Corp.*, 108 IBLA at 36; *see also Pennzoil Oil & Gas, Inc.*, 109 IBLA 147, 154 (1989) (only deductions allowed "'are those *such as* transportation costs, which inflate the price of the product over its value at the wellhead'" (quoting MMS' answer) (emphasis added)).

As for marketing costs, the Department has recognized the appropriateness of deductions for those costs incurred when gas is sold downstream of the leases. *Marathon Oil Co. v. United States* upheld a valuation formula and legal argument advanced by the Department using Marathon's "gross proceeds" in Japan "less the costs of *marketing* and transportation. . . ." 604 F. Supp. at 1384 (emphasis added) (quoting R. Hemingway, *The Law of Oil and Gas* § 7.4 (2d ed. 1983)), *aff'd*, 807 F.2d at 765-66. And in *Arco Oil & Gas Co.*, 112 IBLA 8 (1989), though the Department denied a deduction for a fee paid to a marketing agent, the rule of decision was simply that "[n]o allowance will be recognized by the Department where a lessee, as here, *would have borne similar costs* attributable to the creation and development of markets *regardless* whether production was sold on or adjacent to the lease." *Id.* at 11 (citation omitted) (emphasis added). The Department expressly distinguished Arco's costs from downstream costs that "would not have been incurred by" the lessee "[b]ut for the fact" that the gas was sold "onshore at a point distant from the lease. . . ." *Id.* at 10.

4. *Regulations Incorporated into the Department's Leases*

Oil and gas lease contracts, drafted by the Department on standard forms (*see* L-24-L-43), have varied over the more than 80 years of leasing of federal and Indian lands, but most share four common characteristics relevant to the issues in this case. The form contracts (1) all contain language reserving a royalty on the volume or value of production "from" or "on" the leased land, language mirroring the leasing statutes and historically construed to mean the value at the lease, (2) contain language describing how royalty is to be valued at the lease (when paid in value) or delivered (when paid in kind), (3) in some cases contain a reservation allowing the Secretary to set "reasonable minimum values" for royalty paid in value, and (4) incorporate statutes and regulations into the lease agreement.

Leases issued under the Outer Continental Shelf Lands Act, the source of 80 percent of all gas produced from federal and Indian leases,[2] have varied in their approach to valuation and reservation language, but not in their approach to incorporating statutes and regulations. For example, lease form 3380-1 (October 1969) (L-24) reserves a royalty of a stated percentage of "the amount or value of production saved, removed, or sold *from the leased area.*" (L-24 § 3(a)(1) (emphasis added).) Implementing the value-at-the-lease precept, the lease form explicitly reserves to the Secretary the power to "establish minimum values" for royalty "from this lease, due consideration being given" to several factors relevant to the particular lease, such as the price the lessee receives for production from the lease and prices for like-quality production "in the same field." (L-24 § 3(a)(2).) In contrast, lease form MMS-2005 (March

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2. For the decade of 1991 through 2000, Outer Continental Shelf ("OCS") leases contributed 80 percent of the total royalties received on natural gas from all federal and Indian leases. U.S. Dep't of the Interior, Minerals Mgmt. Serv., *Report on Receipts from Federal and American Indian Leases, Mineral Revenues 2000* ("*Mineral Revenues 2000*") at 10 & 34 (2002).

1986) (L-32) contains no reservation regarding minimum values, but implements the value-at-the-lease precept (L-33 § 6(a)) by detailing the factors the Secretary may consider in determining "the estimated reasonable value of the production" from the lease, again looking to factors relevant to the particular lease. (L-33 § 6(b).)

Both forms incorporate statutes and regulations into the lease agreement in substantially identical ways. Both make the lease subject to "the [OCS Lands] Act." (L-24 & L-32.) Both incorporate all "regulations" issued under the Act and "in existence upon the effective date of this lease." (L-24 & L-32.) Both also incorporate regulations issued under the Act *after* the effective date of the lease to the extent they concern "the prevention of waste and for the conservation of the natural resources of the Outer Continental Shelf, and for the protection of correlative rights therein. . . ." (L-24 & L-32.) The terms "waste," "natural resources," and "correlative rights" are defined terms with meanings not relevant to the value of royalty on oil or gas. *See* 30 C.F.R. § 250.105 (1999).

For federal onshore leases, form 3100-11 (Oct. 1992) (L-36) implements the value-at-the-lease requirement through "regulations on production removed or sold," without specifying whether those royalty value regulations may be subsequently amended. (L-37, § 2) The form reserves "the right to establish reasonable minimum values on products" from the lease. (L-37, § 2.) The form generally incorporates "applicable laws, . . . the Secretary of the Interior's regulations and formal orders in effect as of lease issuance, and . . . regulations and formal orders hereafter promulgated when not inconsistent with lease rights granted or specific provisions of this lease." (L-36.)

5. *The 1997 Rulemaking Proceeding*

Although decades of practice between lessees and the Department had implemented the "value-at-the-lease" principle with few substantive regulations, in 1988 the Department for the first time codified through rulemaking the practice of taking deductions for the cost of transporting gas to a downstream point

of sale. 53 Fed. Reg. 1230, 1257 (Jan. 15, 1988) (promulgating 30 C.F.R. §§ 206.156 & 206.157 to codify transportation deductions from higher downstream prices "to calculate the value of the product at the lease").[3] At the time, pipeline transportation services were unified or "bundled" as one service under a tariff.

In response to a series of initiatives by the Federal Energy Regulatory Commission ("FERC") to "unbundle" the services provided by pipelines, the Department in 1996 undertook another rulemaking to determine what effect FERC's changes might have on the Department's 1988 transportation rules. (L-1-L-10). Prior to its review of the effect of Order 636, MMS agreed that the bundled costs of transportation and marketing were fully deductible for royalty purposes. (App. 33a & L-13). In MMS's view, FERC's unbundling of pipeline services allowed MMS to segregate downstream marketing costs from downstream transportation costs. (L-13.)

After receiving public comment, the Department amended its 1988 regulations to identify which of the unbundled transportation costs would no longer be considered to be costs of "transportation" and, hence, no longer deductible from a downstream price in determining royalty value. (L-11-L-22

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3. The 1988 regulations were adopted, among other reasons, to achieve "consistent application," 53 Fed. Reg. at 1270, of the lease-specific criteria for valuing royalties set out in many of the standard form contracts. (*See, e.g.*, L-33 § 6(b) (listing factors in determining "reasonable estimated value").). For example, the rule reversed the Department's practice of not limiting its claim to royalty to the "gross proceeds" the lessee received at arm's length, *compare Amoco Prod. Co.*, 29 IBLA 234, 236 (1977) (Department not limited) *with* 30 C.F.R. § 206.152(b) (1994) (Department limited); and it clarified how it would view deductions for transportation costs. *Compare Shell Oil Co.*, 70 Int. Dec. 393 (1963) (transportation governed by "relevant factor" test) *with* 53 Fed. Reg. at 1230 (extensive rules on transportation costs "to guide the lessee . . . in the calculation of proper royalty due"). The regulations acknowledged that they did not supersede any "specific provision of any . . . oil and gas lease. . . ." 30 C.F.R. § 206.150(b) (1994).

("the 1997 regulations").) The Department wished to "clarify . . . which cost components or other charges are deductible (related to transportation) and which costs are not deductible (related to marketing). . . ." (L-12)

In the challenged regulations, MMS concluded that lessees have the obligation "to incur *all* marketing costs[,]" wherever incurred. The regulations therefore itemized several downstream costs deemed to be "marketing" rather than "transportation" and no longer deductible. Prominent among these were charges a lessee paid to obtain firm transportation capacity on an interstate pipeline, referred to as "firm demand charges." Even commenters in the rulemaking who opposed the Associations' perspective[4] conceded that "firm demand charges . . . secure access to premium markets [downstream]. . . ." (L-53) In its rule, the Department determined that, to the extent the lessee actually used all the capacity reserved, it could deduct the firm demand charge in full. To the extent, however, the lessee did not use all the reserved capacity in a given month, a pro rata share of the charge would be deemed "unused" and therefore not a transportation cost. (App. 82a & 88a.) The Department drew a similar distinction between the cost of "wheeling" gas through a downstream pipeline hub and the cost assessed for accounting for the volume of gas delivered to the hub and sold there, finding the former part of transportation, the latter marketing.[5] (App. 83a, 86a, 89a & 92a.)

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4. Indians, as lessors, receive all royalties owed under from their leases. The States have an interest by statute in a percentage of the royalties collected from federal lands within their boundaries and from adjacent OCS leases. *See* 30 U.S.C. § 191 (2000); 43 U.S.C. § 1337(g) (2000); *Watt v. Energy Action Educ. Found.*, 454 U.S. 151, 160–61 (1981) (noting California's financial interest in OCS leasing because of statutory entitlement to share of revenues).

5. The Department similarly found charges for downstream aggregation and sale of gas volumes to be marketing costs and non-deductible (App. 85a & 91a), even though commenters and the Department's own analysis agreed these costs "enhance gas values. . . ." (Cont'd)

The agency's sole rationale for denying the deduction of downstream costs enhancing the value of the gas was a purportedly implied duty to market at no cost to the lessor. (L-14.) Under the new regulations, "[t]he lessee must place gas in marketable condition *and market the gas* for the mutual benefit of the lessee and the lessor *at no cost to the Federal Government*." 30 C.F.R. §§ 206.152(i) & 206.153(i) (1999) (emphasis added); *see also* 30 C.F.R. §§ 206.172(i) & 206.173(i) (1999) (creating duty to market at no cost to Indian lessor). In implementing this precept, the 1997 regulations did not adopt any test or definition distinguishing "marketing" from "transportation." *See* 30 C.F.R. § 206.151 (1999); 30 C.F.R. § 206.171 (1999) (no definitions of "transportation" or "marketing").

6. *Proceedings in the District Court*

In separate suits consolidated for briefing, the Associations challenged the 1997 regulations on several grounds and sought declaratory and injunctive relief. On March 28, 2000, the district court granted summary judgment for the Associations and vacated substantial portions of the final regulations. (App. 48a.) In that decision, as amended on September 6, 2000 (App. 17a), the district court vacated the final regulations to the extent they prohibit lessees from deducting the costs of marketing gas downstream of the lease. The district court began its analysis with the meaning of the term "value of production" in the leasing statutes and lease forms.

> The longstanding interpretation of "value of production," one recognized by Interior (at least until the present matter) and affirmed by the courts, is that it refers to the value of oil or gas *at the wells*. Thus, it is well-recognized that the government's

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(L-53). (*Accord* L-44 ("aggregation adds value because it reduces costs for a purchaser." (L-47) (aggregator/marketer cost "[e]nhances the value of the gas because marketers usually aggregate large volumes of production resulting in better deals").)

> royalty interest is limited to the value of production at the lease or wellhead, not in value enhancements resulting from downstream activities. . . . In light of these established principles, the court finds untenable MMS' present position that it has the authority to define value to include downstream costs unrelated to production of the gas.

(App. 36a-37a (citations omitted) (emphasis added).) The court noted that the Department had previously treated "all costs associated with moving gas to downstream markets . . . collectively as transportation costs" and that the Department had not previously attempted to "simply free-ride on the lessees' efforts to obtain value for the gas." (App. 24a-25a.)

Responding to the Department's assertion of an "implied duty to market" at no cost to the lessor, the court carefully reviewed the terms of the government-drafted lease forms. The court observed that the lease forms typically were explicit about what costs were to be borne "'at the expense of the lessee'" (App. 42a-43a (quoting Form 5-157(c) at 2)), creating the inference under principles of contract interpretation that other costs were to be shared proportionately between the lessee and lessor.[6] Noting the provisions allowing the government to amend royalty regulations prospectively and to adopt reasonable minimum values, the court determined those powers were fettered by the government's obligations under the statutes and lease texts to accept the value of the production at the leases. (App. 42a-47a.) Employing the contract law doctrine of *contra*

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6. The district court was unswayed by the government's argument that the Associations agreed that costs incurred to market *at the lease* were not deductible. The Associations acknowledged that the express provision of the lease contracts setting the value of royalty as the value at the lease foreclosed such a deduction. Because value is determined by forces of supply and demand at the given lease, the Associations acknowledged that costs of marketing at the lease (like costs of production on the lease) cannot be deducted. The district court recognized that the added costs of marketing downstream, which add value like other downstream costs, were the focus of the dispute.

proferentem (App. 35a, 42a & 46a), the court found nothing in the structure or text of the lease forms from which the court could imply a lessee's duty to market gas downstream at no cost to the government. (App. 42a-46a.) "Moreover, the court hesitates to endorse an agency's proffered interpretation of a contract in which it has a proprietary interest, particularly where, as here, the interpretation greatly expands the obligations of the private party to the direct benefit of the government." (App. 42a.) Finally, the district court held that deductions for downstream marketing costs cannot be denied based on the Department's arbitrary distinctions between deductible "transportation" costs and non-deductible "marketing" costs. (App. 39a-40a.)

7. *Proceedings in the Court of Appeals*

The court of appeals reversed the district court decision with respect to the deductibility of downstream marketing costs other than firm demand charges. (App. 14a.) At the outset, the court found it a simple matter not to follow contract law because, in the court's view, the Department's "leases give controlling effect not merely to extant Department of Interior regulations but also to ones 'hereafter promulgated.'" (App. 2a.) This feature of the government-drafted lease forms — essentially the only lease language cited by the court of appeals[7] — was enough to demonstrate that "the federal government is not your standard oil-and-gas lessor." (*Id.*) For this reason, the court refused to employ contract law principles "as would a state court interpreting private leases" (App. 6a); unlike those leases, "here the contracts themselves lead us back to the agency."[8] (*Id.*)

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7. The court of appeals also cited lease language reserving the Secretary's right to set "reasonable minimum values" (App. 6a (quoting Form 3100-11 § 2)) but did not explain its relevance to the issue of whether the court should employ contract law principles.

8. The court treated as "a related argument" the Associations' position that because the courts should be reviewing the dispute as *de novo* adjudicators under contract law principles, deference to the Department's interpretations under *Chevron* was inappropriate. (Cont'd)

The court's analysis then turned not to the meaning of "value of production" under the leases and statutes, but to "regulations [which] have historically called for calculation of royalty on the basis of 'gross proceeds.'" (App. 2a (citations omitted).) The court quickly acknowledged that "to abide by the statutory mandate to base royalty on the 'value of production removed or sold from the lease,' Interior has allowed two deductions from gross proceeds when calculating value for royalty purposes[,]" which the court believed "evidently" to be limited to transportation and processing costs.[9] (App. 2a (citations omitted).) The court deferred to the Department's position that it could reasonably implement the value-at-the-lease mandate of the leasing statutes and leases by setting value using the lessee's "gross proceeds" from a sale downstream of the lease, minus deductions limited to costs of transportation and processing. (App. 3a.) ("These are evidently the only deductions from gross proceeds."). With this perceived limit on the kinds of deductions the Department had permitted, the court concluded that "[m]arketing costs have therefore not been deductible."[10]

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(App. 6a-7a.) The court rejected that view, first by citing cases in which courts had applied deferential review of the Department's royalty interpretations, and second by reasoning that one cannot distinguish an agency's role as a party to a contract from any other role in which it could display some form "of agency self-interest." (App. 8a -9a.) From this the court reasoned that reviewing agency interpretations of their own contracts without deference "might come close to overruling *Chevron*. . . ." (*Id.*)

9. In support of this proposition, the court cited a decision of the Interior Board of Land Appeals, *Walter Oil & Gas Corp.*, 111 IBLA 260 (1989). (App. 3a.) The court did not cite or distinguish other Departmental decisions indicating that transportation and processing were merely two examples of deductions for value-adding activities. *See Pennzoil Oil & Gas, Inc.*, 109 IBLA at 154; *Petro-Lewis Corp.*, 108 IBLA at 35-36.

10. In support of this conclusion, the court cited *Arco Oil & Gas Co.*, 112 IBLA at 10-11, without noting the distinction that case drew between marketing costs incurred solely as a result of a downstream

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(App. 3a.) The court did not further inquire whether this bar on marketing deductions, as applied to the costs as issue here, was permitted under the statutes and lease contracts.

Having determined that marketing costs were not deductible, the sole task left for the court of appeals was to determine whether the costs at issue were so similar to transportation costs that the Department was irrational not to treat them so. Even under *Chevron*, the court found unreasonable the Department's distinction between "used" and "unused" firm demand charges. (App. 13a.) "On its face, it is hard to see how money paid for assurance of secure transportation is not 'for transportation'. . . . While some reason may lurk behind the government's position, it has offered none. . . ." (App. 13a-14a.) In contrast, the court deferred to the Department's position that "transportation" costs could not include downstream marketing costs because the distinction between transportation and marketing was "traditional." (App.10a.) The court adopted the position, not adopted by the Department in the rulemaking, that "the difficulty in slicing up marketing costs on the basis of the point of sale" justified treating downstream marketing differently than transportation. (App. 11a.)

Both the producer groups acknowledge that marketing costs for sales at the lease have historically

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sale and more generic forms of marketing costs. *See id.* The court neither noted nor distinguished the Department's prior acceptance of deductions for marketing costs reflected in 52 Public Lands Dec. at 12, or the Ninth Circuit's inclusion of a marketing cost deduction in the "gross proceeds" methodology at issue in *Marathon Oil Co.*, 604 F. Supp. at 1386 (including marketing costs in deductions), *aff'd* 807 F.2d at 766 (leaving it to district court to review particulars of "costs incurred in manufacturing *and selling* liquefied natural gas" (emphasis added)). The government asserted below that the *Marathon* decision did not actually allow marketing deductions. The government failed to show, however, that marketing deductions were not a part of the Department's methodology in the *Marathon* case and failed to show that marketing costs were disallowed.

> been nondeductible. Yet at no point do they offer a persuasive reason for introducing a distinction between marketing for leasehold sales and for "downstream" sales. Indeed, marketing does not even appear readily divisible between the two. . . . Rather, so far as it appears, marketing proceeds by means of the standard modern devices — face-to-face meeting, phone call, internet posting. Unlike the sale itself, which will presumably involve shifts of title and possession at specified points, marketing has no locus — certainly none that ineluctably tracks the point where title shifts.

(App. 9a (citations omitted).) Because marketing has "no locus,"[11] (App. 9a) the court dismissed the Associations' argument — that barring deductions for downstream marketing costs was inconsistent with valuation at the lease — as "an elegant theory" and "metaphysical." (App. 10a.)

The court of appeals did not disagree, however, with the district court's holding that no duty to market could be implied in the lease; nor did it reverse the district court's factual finding that the "downstream marketing costs made non-deductible by the Rule, were, in fact, previously deducted. . . ." (App. 32a-33a.)[12]

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11. The court did not rely, however, on its "no locus" reasoning in reversing the district court on the costs at issue here. For example, it upheld the Department's distinction between deductible "wheeling" fees for moving gas through a downstream pipeline hub and non-deductible "hub transfer fees" for accounting for the volume of gas moved into the hub and sold. (App. 11a-12a.) Obviously, hub transfer fees have a defined locus downstream of the lease: the accounting is performed by the hub operator for gas moved into the hub and sold at the hub. The locus is identical to that of the deductible wheeling service provided by the hub operator. The court instead simply acceded to the Department's characterization that the transfer fees were "part of a 'sales transaction.'" (App. 11a.)

12. Judge Sentelle concurred, but found "troubling" the court's "discussion of the applicability of *Chevron* deference to the interpretation (Cont'd)

Petitioners timely filed petitions for rehearing and suggestion for rehearing *en banc*. On June 21, 2002, the D.C. Circuit denied the petitions.

REASONS FOR GRANTING THE PETITION

I. THE DECISION BELOW CONFLICTS WITH THIS COURT'S PRECEDENTS HOLDING THAT GOVERNMENT CONTRACTS ARE GOVERNED BY THE LAW APPLICABLE TO PRIVATE CONTRACTS.

In this case, the District of Columbia Circuit improperly exempted the Department from the usual rule that "[w]hen the United States enters into contract relations, its rights and duties therein are governed generally by the law applicable to contracts between private individuals." *Franconia Assocs. v. United States*, __ U.S. __, __, 122 S. Ct. 1993, 2001 (2002) (quoting *Mobil Oil*, 530 U.S. at 607 (internal quotation marks omitted)).[13] Chiding the Associations for "implicitly asking us to treat the matter as would a state court interpreting private leases" (App. 6a), the court of appeals declared that "the federal government is not your standard oil-and-gas lessor." (App. 2a.) And to honor the government's special status, the court looked neither to the substantive provisions of the lease contracts nor to "the principles of general contract law," *Priebe & Sons, Inc.*

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of statutes governing contracts in which the agency has a financial interest." (App. 15a.)

13. *Accord S.R.A., Inc. v. State of Minnesota*, 327 U.S. 558, 564 (1946) ("Normally, contracts between the United States and others are construed as contracts between private parties") (citing *Lynch v. United States*, 292 U.S. 571, 579 (1934)); *Clearfield Trust Co. v. United States*, 318 U.S. 363, 369 (1943) ("the United States does business on business terms") (quoting *United States v. Nat'l Exch. Bank*, 270 U.S. 527, 534 (1926)); *Perry v. United States*, 294 U.S. 330, 352 (1935) ("When the United States, with constitutional authority, makes contracts, it has rights and incurs responsibilities similar to those of individuals who are parties to such instruments.") (citation omitted); *United States v. Bostwick*, 94 U.S. 53, 66 (1876) (same); *Cooke v. United States*, 91 U.S. 389, 398 (1875) (same).

v. United States, 332 U.S. 407, 411 (1947),[14] but looked instead to "administrability" and the alleged "difficulty in slicing up marketing costs on the basis of the point of sale. . . ." (App. 11a.)

The court of appeals never addressed the premise on which the Department based the 1997 regulation: that the statutory and lease contract provisions limiting the government's royalty claim to the value of production at the lease was trumped by the lessees' "implied" contractual duty to market production without cost to the lessor. The court's failure to focus on the rationale employed by the agency of course ran afoul of *SEC v. Chenery Corp.*, 332 U.S. 194, 196 (1947) (court must rely "solely on the grounds invoked by the agency"). More fundamentally, its failure steered the court away from the core issue in the case: whether the alleged implied duty was consistent with the bargain in the lease contract that lessees owed royalties on the value of production at the lease.

Under general contract principles, the Department's denial of deductions for downstream marketing costs would fail at once, as the district court properly determined.[15] (App. 46a.) Contrary

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14. *Accord United States v. Standard Rice Co.*, 323 U.S. 106, 111 (1944)

> the United States as a contractor must be treated as other contractors under analogous situations. When problems of the interpretation of its contracts arise the law of contracts governs. . . . We will treat it like any other contractor and not revise the contract which it draws on the ground that a more prudent one may have been made.

(citations omitted); *Reading Steel Casting Co. v. United States*, 268 U.S. 186, 188 (1925) ("The [government] contract is to be construed and the rights of the parties are to be determined by the application of the same principles [of contract law] as if the contract were between individuals.").

15. *See, e.g., Piney Woods Country Life School v. Shell Oil Co.*, 726 F.2d 225, 240 (5th Cir. 1984) ("lessors may be charged with processing costs, by which we mean all expenses, subsequent to

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to the court of appeals' assumption that marketing has "no locus" (App 9a), the costs challenged by petitioners here are those having a "locus" uniquely downstream of the lease; and these activities undisputedly add value to the gas beyond its value at the lease. In the rulemaking below, the Department and commenters never contended otherwise. Public comments in the rulemaking record — even from those opposing the Associations' interests — conceded that fees spent for services such as downstream aggregation and marketing of gas volumes "enhance gas values. . . ." (L-53). *See supra* at 11 & n.5. By not allowing lessees to deduct these costs, the Department receives royalty at a value higher than the value of the gas at the lease. It is contrary to the express mutual understanding of lessees and the lessor — that values at the lease are all the lessees owe — to allow the Department to demand an admittedly higher value. *See NRM Corp. v. Hercules Incorp.*, 758 F.2d 676, 681 (D.C. Cir. 1985) ("the judicial task in construing a contract is to give effect to the mutual intentions of the parties"); *Restatement (Second) of Contracts* § 201(1) (1981) (same). The court of appeals simply ignored the lease contracts and governing statutory standards on this point.

The lease contracts also allow the government to take its royalty in kind; but if it wishes to receive delivery of the production free of cost, it must take the delivery at the lease. *See supra* at 6. The government never disputed below that if it took its royalty on natural gas in kind, it would have to pay the

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production relating to the processing, transportation, and *marketing* of gas and sulfur") (emphasis added); *Schroeder v. Terra Energy, Ltd.*, 565 N.W.2d 887, 892 (Mich. App. 1997), *leave to appeal denied*, 587 N.W.2d 638 (Mich. 1998) ("*marketing* and other fixed costs incurred by defendant . . . are properly deducted . . . to determine the 'gross proceeds at the wellhead'") (emphasis added); *Wood v. TXO Production Corp.*, 854 P.2d 880, 881 (Okla. 1992) (once the lessee has made the product available for market, "any further expenses beyond the lease property must be borne proportionately by the lessor and the lessee") (citation omitted).

same downstream marketing costs at issue here if it sold its gas downstream of the lease. Indeed, in construing this lease language, the Department has long concurred that "royalty based on the value of [production] at the lease is the economic equivalent of the value of the royalty [when taken in kind]." *Petro-Lewis Corp.*, 108 IBLA at 42 n.8; *accord Mobil Producing Texas & New Mexico, Inc.*, 115 IBLA at 172; *Kerr-McGee Corp.*, 22 IBLA 124 (1975). Given, as the parties agree, that the lessees do not pay the government's downstream marketing costs when it takes the gas in kind, it cannot be inferred they intended the opposite when the government takes its economic equivalent in value. *See* Arthur L. Corbin, *Corbin on Contracts* § 538, at 55 (1960); *Restatement (Second) of Contracts* §§ 201(1) & 203(a); *see also United States v. Western Electric Co.*, 12 F.3d 225, 230 (D.C. Cir. 1993) (a contract should be interpreted to give meaning to each of its provisions and in accordance with the understanding of the parties when written). Again, the court of appeals ignored the lease language on this point.

And at no point below did the government attempt to show how its assertion of an implied duty to market at no cost to the lessor comports with general contract law principles governing implied clauses in contracts. *See Adkins v. Adams*, 152 F.2d 489, 491 (7th Cir. 1945) ("implication must arise from the language employed in the instrument or be indispensable to effectuate the intention of the parties"). Under general contract law, as already applied to the Department's own lease contracts, courts will not infer that the parties agreed to a provision which the Department could have included in its lease contracts but failed to include. *Gen. Petroleum Corp.*, 73 F. Supp. at 234-38 (rejecting government assertion of implied power under the lease contract to fix unilaterally a minimum value for royalty oil); *see also Standard Rice Co.*, 323 U.S. at 111 (the court will not revise a government contract "on the ground that a more prudent one may have been made"). The district court determined, without contradiction by the court of appeals, that the "terms of various federal and Indian gas lease forms . . . do not support

MMS' contention that federal gas leases contain an implied covenant to market gas at no cost." (App. 42a.) *See Mobil Oil*, 530 U.S. at 616 (accepting lower court interpretation of OCS lease when court of appeals "did not disagree with that interpretation"). Indeed, the court of appeals agreed with the district court (without grasping the incongruity) that "the producers are under no duty to market 'downstream' and may opt to sell at the leasehold. . . ." (App. 10a.)

In sum, rather than employing contract principles to determine whether the 1997 regulations were consistent with the lease bargain that royalties were valued at the lease, and rather than determining whether an implied duty trumped that bargain, the court of appeals deferred to an agency-created distinction between transportation and downstream marketing. That distinction appears nowhere in the statutes or the lease contracts, however, and did not to appear in the regulations prior to this case. The decision of the court of appeals places the Department beyond "the law applicable to contracts between private individuals," in contravention of *Mobil Oil*, 530 U.S. at 607.

II. THE DECISION BELOW CONFLICTS WITH THE PRECEDENTS OF THIS COURT AND WITH THOSE OF THE FIRST, FOURTH, FIFTH, AND FEDERAL CIRCUITS WHICH HAVE HELD THAT DEFERENCE DOES NOT ATTACH TO GOVERNMENT INTER-PRETATIONS OF CONTRACTS IT DRAFTS AND SIGNS.

The court of appeals held that *Chevron* deference is required because federal oil and gas leases "give controlling effect not merely to extant Department of Interior regulations but also to ones 'hereafter promulgated.'" (App. 2a.) The court did not, of course, identify what ambiguity surrounded the Department's obligation to accept the value of natural gas at the lease; and none have gainsaid that the downstream costs in question add

value beyond the value of the gas at the lease.[16] But even if there were sufficient ambiguity to make the appropriateness of deference debatable, this holding undermines the application of the contract law doctrine of *contra proferentem* in conflict with *United States v. Seckinger*, 397 U.S. 203, 210 (1970). And it places the District of Columbia Circuit at odds with rulings of the First, Fourth, Fifth, and Federal Circuits, as well as with some of its own decisions. (App. 8a (citing earlier cases).)

1. *Chevron* deference proceeds from the notion that Congress entrusts the executive departments of government to create law in circumstances where Congress deems it inexpedient to legislate in great detail. Where Congress has left it to an agency to "fill[ ] a space in enacted law," *United States v. Mead Corp.*, 533 U.S. 218, 229 (2001), "a reviewing court has no business rejecting an agency's exercise of its generally conferred authority to resolve a particular statutory ambiguity simply because the agency's chosen resolution seems unwise . . .," and so must defer to a reasonable agency interpretation. *Id.* This notion has no force, however, where the binding power of the agency's position comes only through the contractual consent of the private party. There, at least absent some special indication from Congress, the presumption is that the government agency is on equal footing with its counter-party,

16. This case does not concern, therefore, whether courts should defer when the Department has exercised the power reserved in some lease contracts to determine what method should be used to calculate the "reasonable estimated value" of production *at the lease* or to set a reasonable minimum value of the production there. *See supra* at 9 & 10 n.3. Here the rulemaking record discloses no purported exercise of that power, or consideration of the several factors enumerated in the relevant lease clauses. *See Mobil Oil*, 530 U.S. at 615 (rejecting government reliance on a reserved authority to suspend leases when government "does not explain how" the requisite for exercising that power "was satisfied here"). Instead, the Department in this case has categorically denied deductions for downstream marketing costs with the admitted result of imposing a royalty value greater than value at the lease, raising the question whether the lease contracts (and incorporated statutory provisions) allow this.

and the principles of contract law will apply. *Mobil Oil*, 530 U.S. at 607; *Reading Steel Casting Co.*, 268 U.S. at 188.

The court of appeals could point to nothing in the leasing statutes or their legislative history suggesting that Congress departed from the usual rule that "'[w]hen the United States enters into contract relations, its rights and duties therein are governed generally by the law applicable to contracts between private individuals.'" *Mobil Oil*, 530 U.S. at 607-08 (quoting *Winstar Corp.*, 518 U.S. at 895); *see also supra* 18 n.13. Because federally issued or approved oil and gas leases are contracts, *Mobil Oil*, 530 U.S. at 607, they are (even under the court of appeals' own precedent) "subject to interpretation under the neutral principles of contract law, not the deferential principles of regulatory interpretation." *Mesa Air Group Inc. v. Dep't of Transp.*, 87 F.3d 498, 503 (D.C. Cir. 1996); *see Standard Rice Co.*, 323 U.S. at 110.

Under this Court's precedents, when the matter being interpreted is a government-drafted contract, ambiguities or omissions in the contract are first resolved by traditional tools of contract interpretation. *See Priebe & Sons, Inc.*, 332 U.S. at 411. Among these are the doctrine of *contra proferentem*,[17] *Seckinger*, 397 U.S. at 210, and the rule animating the holding in *Continental Oil Co.*: that a court will not imply an obligation that the drafter failed to express. 184 F.2d at 810 (allowing "one party to a contract to fix the obligation of the other party by unilateral action . . . cannot have been within the contemplation of the parties in the absence of an express reservation to that effect"). Because the Department is treated like any private party when it executes a lease, *see Mobil Oil*, 530 U.S. at 607-08, the Department must accept that all drafters of mineral leases and other contracts are subject to the doctrine of *contra proferentem*.

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17. *See Mastrobuono v. Shearson Lehman Hutton, Inc.*, 514 U.S. 52, 62-63 (1995) (noting the "common-law rule of contract interpretation that a court should construe ambiguous language against the interest of the party that drafted it").

See, e.g., *Seckinger*, 397 U.S. at 210. In fact, the Department's precedents accept precisely this point, holding that *contra proferentem* applies in construing royalty provisions in leases *and* regulations. *Exxon Co. U.S.A.*, 113 IBLA 199, 206 (1990) ("If a regulation is ambiguous, any doubt as to its meaning should be resolved favorabl[y] to the lessee"); *Superior Oil Co.*, 12 IBLA 212, 224 (1973) (employing *contra proferentem*).

Thus, as the Department's own precedents indicate, the incorporation of regulations into the lease contract does not transform the character of a court's review of the agency's action; the matter before the court remains the interpretation of contract language. The regulations at issue here illustrate this very point. The regulations purport to implement the Department's interpretation that its lease contracts create an implied duty to market at no cost to the lessor. (*See* App. 81a-82a, 87a-88a & L-14.) The validity of this interpretation, which results in royalty value in excess of the value of production at the lease, must be adjudged under the neutral principles of contract interpretation, including the doctrine of *contra proferentem*, to determine its consistency with the lease language (incorporating the statutory provisions) that royalty is due on value at the lease.

Nothing in the language of the lease contracts supports the contrary view of the court of appeals. Under the lease language quoted by the court for onshore leasing, the 1997 regulations could not be incorporated into the contract unless they were "not inconsistent with lease rights granted or specific provisions of this lease" (App. 6a, citing Form 3100-11 at 1), such as the provision valuing royalty at the lease. The court of appeals did not explain why it was appropriate to defer to the Department's assumed but unstated "determination" (never documented in the record) that the denial of downstream marketing costs satisfied this prerequisite established by the lease contract. And in giving deference to the Department, the decision below utterly failed to address the express restrictions limiting what future rules may be incorporated into OCS leases. *See Mobil Oil*, 530 U.S. at 615-17 (noting "the contracts' specific temporal

restrictions" in OCS leases, subjecting them to then-existing regulations and to future regulations "'which provide for the prevention of waste and the conservation of' Outer Continental Shelf resources").

The court of appeals' holding is the death knell of *contra proferentem* in disputes arising as to the meaning of contracts the government drafts, especially lease contracts offered "on a take-it-or-leave-it basis." (App. 42a.) In the court of appeals' view, ambiguities are not resolved in favor of the non-drafting party, *see Seckinger*, 397 U.S. at 210, but rather resolved with deference given to the views of the drafter. The court's application of *Chevron* turns principles of contract law on their head. When the government is a party to a contract it has drafted, *Seckinger* necessarily stops *Chevron* in its tracks.

2. The D.C. Circuit's decision also conflicts with those of the First, Fourth, Fifth, and Federal Circuits which have held that deference cannot attach to government interpretations of contracts it drafts. The First Circuit, through Chief Judge (now Justice) Breyer, rejected a plea of the U.S. Forest Service for deference to its interpretation of a "Term Permit" it had drafted under regulatory powers, finding the permit to be a kind of contract. "*Chevron* does not dictate a reviewing court's attitude towards the language of a contract, or of a document that resembles a contract. . . ." *Meadow Green-Wildcat Corp. v. Hathaway*, 936 F.2d 601, 605 (1st Cir. 1991). The Fourth Circuit has held the same. *Burgin v. Office of Pers. Mgmt.*, 120 F.3d 494, 497-98 (4th Cir. 1997).[18]

The Federal Circuit, for its part, holds that no deference is given to agency interpretations of regulations incorporated into government contracts (or of the contracts themselves) where, as here, the government has a financial stake in the contract. *S. Cal. Edison Co.*, 226 F.3d at 1357; *Brown v. United States*, 195 F.3d 1334, 1340 (Fed. Cir. 1999); *Metric Constructors, Inc.*

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18. The Eleventh Circuit, however, has acknowledged its split with the Fourth Circuit on this question. *Muratore v. Office of Pers. Mgmt.*, 222 F.3d 918, 922-23 (11th Cir. 2000).

v. NASA, 169 F.3d 747, 751 (Fed. Cir. 1999) (reviewing NASA "contract interpretation without deference"); *Lockheed Martin IR Imaging Systems Inc. v. West*, 108 F.3d 319, 322 (Fed. Cir. 1997) (no deference to Army interpretation of a contract to which it is a party); *United States v. Boeing Co.*, 802 F.2d 1390, 1393 (Fed. Cir. 1986) ("interpretation of regulations which are incorporated into government contracts is a question of law which this court is free to resolve").[19]

In a closely related context, the Fifth Circuit in *Tennessee v. FERC*, 17 F.3d 98 (5th Cir. 1994), refused to defer to FERC's construction of a third party natural gas agreement within its regulatory jurisdiction, on the ground that the court "review[s] the construction of natural gas contracts freely." *Id.* at 102 (citing *El Paso Natural Gas Co. v. FERC*, 881 F.2d 161, 164 (5th Cir. 1989)). Instead, where the agency relied on the words of the contract, and not on any specialized expertise, the court applied the normal rules of contract interpretation. *Id.* (citing *Mid Louisiana Gas Co. v. FERC*, 780 F.2d 1238, 1243 (5th Cir. 1986)). Given that the Fifth Circuit would not defer to the agency's interpretation of a contract to which it is not a party, it would not defer to the agency's interpretation of contracts in which it has a proprietary interest.

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19. In contrast to the Federal Circuit, the court of appeals below holds that deference is appropriate because the leases incorporate the Department's regulations. Even if the court of appeals were correct, its application of *Chevron* was in error. Below, all parties and both courts acknowledged the longstanding construction that value under the statute means value at the lease. Inquiry into the meaning of the statute therefore stops at "Step One" of the *Chevron* analysis. *See Chevron*, 467 U.S. at 842-43. If that point were not enough alone, the court of appeals also failed in its duty under "Step Two" of *Chevron* to determine whether the Department's refusal to pay its share of downstream marketing costs, incurred to add value beyond the value of the gas at the lease, was "manifestly contrary" to the statute's value-at-the-lease requirement. *See id.* at 844. Even under *Chevron*, no deference is owed to the simple artifice of incorporating a regulation that provides for royalty on a value higher than that allowed by statute or contract.

Certiorari is therefore warranted to resolve conflicts among the Circuits on whether deference is owed to agency interpretations of contracts and regulations incorporated into contracts the agency had drafted.

III. REVIEW IS WARRANTED NOW TO PROVIDE CERTAINTY TO FEDERAL CONTRACTORS AND LESSEES THAT FEDERAL AGENCIES CANNOT USE THEIR RULEMAKING POWERS TO CEASE DOING "BUSINESS ON BUSINESS TERMS."

The Associations represent the vast majority of persons operating oil and gas leases on federal and Indian lands. It is highly unlikely that a challenge to the regulations will be brought in any other Circuit. In this respect, this case is like many others for which this Court has accepted review, in which the government's failure to adhere to the general principles of contract law is unlikely to be raised in multiple circuits.

Recognizing the overriding national importance of fair dealing by the government in the realm of contracting, this Court has frequently reviewed cases involving disputes over federally-drafted contracts to assure that "[t]he United States does business on business terms." *Nat'l Exch. Bank*, 270 U.S. at 534.[20] Government mineral leasing is not exempt from this rule. "The Government's rights and obligations as lessor of public lands are no different from those of any other lessor[,]" *Standard Oil Co. v. Hickel*, 317 F. Supp. 1192, 1197 (D. Alaska 1970), *aff'd sub nom., Standard Oil Co. v. Morton*, 450 F.2d 493 (9th Cir. 1971), a point this Court underscored two terms ago in *Mobil Oil*.

At the end of 2000, approximately 61,000 federal and Indian oil and gas leases were in force, of which approximately 25,000 were producing. *Mineral Revenues 2000* at 119, 124 & 126.

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20. *See, e.g., Winstar Corp. v. United States*, 64 F.3d 1531 (Fed. Cir. 1995), *cert. granted*, 516 U.S. 187 (1996); *Hercules v. United States*, 24 F.3d 188 (Fed. Cir. 1994), *cert. granted*, 514 U.S. 1049 (1995); *Gardner v. Brown*, 5 F.3d 1456 (Fed. Cir. 1993), *cert. granted*, 511 U.S. 1017 (1994).

In that same year, federal and Indian leases produced twenty percent of the oil and twenty-six percent of the natural gas produced in the United States. *Mineral Revenues 2000* at 47, 73 & 91; Energy Information Admin., *Annual Energy Outlook 2002* at 88 & 171. The decision below, by allowing the Department unilaterally to amend its lease bargain through regulation, unsettles the expectations of the contracting parties in tens of thousands of oil and gas lease contracts, a significant risk to the national interest in enhancing domestic production. *See* 43 U.S.C. §§ 1332(3) & 1802(1) & (2) (2000); *see also Winstar*, 518 U.S. at 886 (adherence to the general rules of contract law is essential to preserving "the Government's capacity as a reliable, straightforward contractor").

CONCLUSION

For the reasons stated above, this Court should grant the petition for a writ of certiorari.

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APPENDIX

APPENDIX A — OPINION OF THE UNITED STATES COURT OF APPEALS FOR THE DISTRICT OF COLUMBIA CIRCUIT DATED AND DECIDED FEBRUARY 8, 2002

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

Argued December 5, 2001 Decided February 8, 2002

No. 00-5404

INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA,

APPELLEE,

v.

WALLACE P. DEWITT,
ACTING ASSISTANT SECRETARY,
FOR LAND AND MINERALS MANAGEMENT, DOI AND
UNITED STATES DEPARTMENT OF THE INTERIOR,

APPELLANTS.

Consolidated with
00-5405

Appeals from the United States District Court
for the District of Columbia
(No. 98cv00531)
(No. 98cv00631)

Appendix A

Before: SENTELLE and ROGERS, *Circuit Judges*, and WILLIAMS, *Senior Circuit Judge.*

Opinion for the Court filed by *Senior Circuit Judge* WILLIAMS.

Concurring opinion filed by *Circuit Judge* SENTELLE.

WILLIAMS, *Senior Circuit Judge*: Producers of natural gas typically lease the mineral rights and compensate the owner by means of a royalty calculated as some fraction (such as 1/8 or 1/6) of the value of the gas produced. In exchange, lessees agree to bear the costs and risks of exploration and production. Federal and Indian gas leases are no exception.

But the federal government is not your standard oil-and-gas lessor. For the detailed ascertainment of the parties' rights, its leases give controlling effect not merely to extant Department of Interior regulations but also to ones "hereafter promulgated." See, e.g., Department of Interior, Form 3100-11, at p. 1 (1992). The regulations have historically called for calculation of royalty on the basis of "gross proceeds." See, e.g., 30 C.F.R. §§ 206.152(h) (federal unprocessed gas), 206.153(h) (federal processed gas). But to abide by the statutory mandate to base royalty on the "value of the production removed or sold from the lease," 30 U.S.C. § 226(b)(1)(A), Interior has allowed two deductions from gross proceeds when calculating value for royalty purposes. One deduction relates to certain processing costs and is irrelevant here; the other is for transportation costs when production is sold at a market away from the lease. 30 C.F.R. §§ 206.157, 206.177; see also Final Rule, *Revision of Oil*

Appendix A

Product Valuation Regulations and Related Topics, 53 Fed. Reg. 1184, 1186 (1988). These are evidently the only deductions from gross proceeds. *Walter Oil & Gas Corp.*, 111 IBLA 260, 265 (1989). Marketing costs have therefore not been deductible. See, e.g., *Arco Oil & Gas Co.*, 112 IBLA 8, 10-11 (1989).

In the mid-1980s a series of rulemakings by the Federal Energy Regulatory Commission somewhat changed the circumstances to which these principles applied. Previously, producers most commonly sold gas at the wellhead to natural gas pipeline companies, which then transported it and sold it to local distribution companies; less commonly, they made direct sales from producer to an end user or distributor, with the pipeline providing only transportation. See, e.g., *FPC v. Transcontinental Gas Pipeline Corp.*, 365 U.S. 1, 4 (1961). But FERC, starting with Order No. 436 and culminating in Order No. 636, in effect transformed the pipelines into "open-access" transporters and required them to separate sales from transportation services, Final Rule, *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation, and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, 57 Fed. Reg. 13,267, 13,279/1 (1992) ("Order 636"), to charge unbundled rates for services such as transmission and storage, *id.* at 13,288-89, and to assign their merchant services to functionally independent market affiliates, *id.* at 13,298; see also 18 C.F.R. § 161 (1988) (restricting pipelines from favoring such affiliates). In effect, the pipelines as such became almost exclusively transporters of gas, and direct sales by producers to end users, distributors, or merchants became the norm.

In response to these changes, the Department of Interior in 1997 amended its gas royalty regulations "to clarify [its] existing policies" and to prevent lessees from claiming "improper deductions on their royalty reports and payments." Final Rule, *Amendments to Transportation Allowance Regulations for Federal and Indian Leases to Specify Allowable Costs and Related Amendments to Gas Valuation Regulations*, 62 Fed. Reg. 65,753/3-65,754/1 (1997) ("Final Rule"). Two trade associations representing the gas producers (American Petroleum Institute for the "majors," Independent Petroleum Association of America for the "independents") brought suits challenging these regulations as arbitrary and capricious. Their primary contention was that Interior had impermissibly refused to permit deductions for costs incurred in marketing gas to markets "downstream" of the wellhead. Dispute focused especially on Interior's denial of deductions for (1) fees incurred in aggregating and marketing gas with respect to downstream sales; (2) "intra-hub transfer fees" charged by pipelines for assuring correct attribution of quantities to particular transactions (*not* for the physical transfers themselves); and (3) any "unused" pipeline demand charge (i.e., the portion of a demand charge paid to secure firm service but relating to quantities in excess of a producer's actual shipments).

The district court granted summary judgment for the producers in broad terms, *Independent Petroleum Association of America v. Armstrong*, 91 F. Supp. 2d 117, 130 (D.D.C. 2000) ("*IPAA*"), but then granted Interior's Rule 59(e) motion for clarification, *Independent Petroleum Association of America v. Armstrong*, No. 98-00531(RCL) (D.D.C. Sept. 1, 2000) ("Amended Order") (unpublished opinion). When the

dust had settled, the upshot was to declare that the relevant regulations were unlawful "to the extent that they impose a duty on lessees to market gas downstream . . . and disallow the deduction of downstream marketing costs," including the intra-hub transfer fees, and to the extent that they limit deduction for firm demand charges to the applicable rate multiplied by the "actual volumes transported." Amended Order, slip op. at 2. The modified order also specified that a producer that sold unused pipeline capacity must credit the United States with the resulting revenue. *Id.* Interior now appeals.

We review the district court's ruling de novo, "as if the [agency's] decision had been appealed to this court directly." *Kosanke v. Dep't of Interior*, 144 F.3d 873, 876 (D.C. Cir. 1998) (quoting *Dr. Pepper/Seven-Up Cos. v. FTC*, 991 F.2d 859, 862 (D.C. Cir. 1993)). On the deductibility of marketing costs we find no legal error in Interior's rule and therefore reverse the district court; on the "unused" demand charge issue, we affirm the district court.

* * *

The producers argue that we owe no deference to Interior's judgments here, saying that the case involves interpretation of contracts, not of a statute. Thus they call for "interpretation under neutral principles of contract law, not the deferential principles of regulatory interpretation." *Mesa Air Group, Inc. v. Department of Transportation*, 87 F.3d 498, 503 (D.C. Cir. 1996). But see *National Fuel Gas Supply Corp. v. FERC*, 811 F.2d 1563, 1570-71 (D.C. Cir. 1987) (applying a *Chevron* framework to agency interpretation of contracts, though expressing concern where the agency is self-interested). Thus the producers' briefs point

(rather summarily) to state court decisions, implicitly asking us to treat the matter as would a state court interpreting private leases. But here the contracts themselves lead us back to the agency. As we said, they incorporate the regulations and recognize Interior's authority to modify them. E.g., Form 3100-11, at p. 1 ("Rights granted are subject . . . to regulations and formal orders hereafter promulgated when not inconsistent with lease rights granted or specific provisions of this lease."); *id.* at § 2 (reserving to Interior "the right to establish reasonable minimum values on products"); see also, e.g., Department of Interior, Form MMS-2005, § 6(b) (1986); Department of Interior, Form BAO- 436A, § 3 (1993).

Of course the application of new rules to pre-existing leases may involve "secondary retroactivity": a new rule that legally has only "future effect," and is therefore not subject to doctrines limiting retroactive effect, may still have a serious impact on pre-existing transactions. See, e.g., *Bowen v. Georgetown University Hospital*, 488 U.S. 204, 219-20 (1988) (Scalia, J., concurring). Interior's own rules recognize the possibility, explicitly repudiating any authority to alter the royalty rate except downwards (i.e., in the lessee's favor). 30 C.F.R. § 202.52(a). The legal effect of such secondary retroactivity is to add a nuance to ordinary review for whether the agency has been arbitrary or capricious: we review to see whether disputed rules are "reasonable, both in substance and in being made retroactive." *U.S. Airwaves, Inc. v. FCC*, 232 F.3d 227, 233 (D.C. Cir. 2000). But this added nuance is quite different from a general denial of deference.

In a related argument, producers urge that deference to Interior's interpretation of the statute under *Chevron U.S.A.*,

Inc. v. Natural Resources Defense Council, Inc., 467 U.S. 837 (1984), is inappropriate for regulations that affect contracts in which Interior has financial interests.

But in the mineral leasing statutes Congress has granted rather sweeping authority "to prescribe necessary and proper rules and regulations and to do any and all things necessary to carry out and accomplish the purposes of [the leasing statutes]." 30 U.S.C. § 189 (federal lands); see also 25 U.S.C. §§ 396, 396d (tribal lands); 43 U.S.C. § 1334(a) (outer Continental shelf). These "purposes," of course, include the administration of federal leases, which involves collecting royalties and determining the methods by which they are calculated. See *California Co. v. Udall*, 296 F.2d 384, 387-88 (D.C. Cir. 1961); see also *Independent Petroleum Association v. Babbitt*, 92 F.3d 1248, 1262 n.6 (D.C. Cir. 1996) (Rogers, J., dissenting) (recognizing that Congress authorized Interior "to prescribe regulations governing mineral leases").

It is thus not surprising that the cases do not support producers' theory. Though no circuit appears ever to have ruled specifically on the issue of deference to financially self-interested agencies, courts have regularly applied *Chevron* in royalty cases. In *California Co.*, we deferred to Interior's interpretation of the word "production" for purposes of calculating royalty, noting the Department's duties both to protect the public interest in royalties and to assure "incentive[s] for development." 296 F.2d at 388. Similarly, in *Mesa Operating Limited Partnership v. Department of Interior*, 931 F.2d 318 (5th Cir. 1991), the Fifth Circuit applied *Chevron* in determining whether certain

reimbursements were subject to royalty. *Id.* at 322; see also *Enron Oil & Gas Co. v. Lujan*, 978 F.2d 212, 215 (5th Cir. 1992) (applying *Chevron* to issue of whether state tax reimbursements are subject to royalty); *Marathon Oil Co. v. United States*, 807 F.2d 759, 765- 66 (9th Cir. 1986) (applying *Chevron* to Interior's use of a "net-back" method for calculating value for royalty purposes). Our reference in *California Co.* to Interior's necessary concern for producer incentives in effect invoked Interior's role as a repeat player, which would cause Interior to pay severely if it acquired a reputation for pulling the rug out from under the generally accepted meaning of existing leases.

In support of their position, producers principally rely on language from *Transohio Savings Bank v. Office of Thrift Supervision*, 967 F.2d 598 (D.C. Cir. 1992), where we expressed reluctance to apply *Chevron* "to an agency interpretation of a statute that will affect agreements to which the agency is party." *Id.* at 614. But we ultimately found that Congress's intent was clear and thus had no occasion to grant (or withhold) deference. See *id.* at 614-15. In the end, of course, the availability of *Chevron* deference depends on congressional intent, but our application of such deference in the face of a recognized risk of agency self-aggrandizement, such as interpretations of their own jurisdictional limits, *Oklahoma Natural Gas Co. v. FERC*, 28 F.3d 1281, 1283-84 (D.C. Cir. 1994), necessarily means that self-interest alone gives rise to no automatic rebuttal of deference. Indeed, given the ubiquity of some form of agency self-interest, see generally Dennis C. Mueller, Public Choice 156-70 (1979); William A. Niskanen, Jr., Bureaucracy and Representative Government (1971), a general withdrawal of

deference on the basis of agency self-interest might come close to overruling *Chevron*, a decision far beyond our authority. We see no indication here of a special intent to withhold deference.

* * *

"Downstream" marketing costs and intra-hub transfer fees. We find nothing unreasonable in Interior's refusal to allow deductions for so-called "downstream" marketing costs. See Final Rule, 62 Fed. Reg. at 65,756. Both the producer groups acknowledge that marketing costs for sales *at the lease* have historically been nondeductible. API Br. at 30; IPAA Br. at 22. Yet at no point do they offer a persuasive reason for introducing a distinction between marketing for leasehold sales and for "downstream" sales. Indeed, marketing does not even appear readily divisible between the two, as it would be if lessees stood on their lease boundaries and operated the equivalent of a lemonade stand for leasehold sales, but traveled to distant cities for "downstream" ones. Rather, so far as it appears, marketing proceeds by means of the standard modern devices — face-to-face meeting, phone call, internet posting. See, e.g., Order 636, 57 Fed. Reg. at 13,282/2 (describing electronic bulletin boards, then precursors to the Internet, as having become "standard industry-wide practice"). Unlike the sale itself, which will presumably involve shifts of title and possession at specified points, marketing has no locus — certainly none that ineluctably tracks the point where title shifts.

To be sure, transaction costs may be higher for sales in the current market; sales to a single (perhaps monopsonistic)

pipeline may have been painfully simple. But a change in the dimension of a cost is hardly an argument for its reclassification, as the Interior Board of Land Appeals has observed. *Arco*, 112 IBLA at 11. And because the producers are under no duty to market "downstream" and may opt to sell at the leasehold, see *IPAA*, 91 F. Supp. 2d at 123 ("Interior concedes that plaintiffs are free to sell or beneficially consume gas at the wellhead only, rather than pursue downstream sales."), a complaint based on the cost change is especially weak.

Producers further argue that downstream marketing adds to the value of the gas at the leasehold, and thus that the royalty owner should share the costs. In support, they propose what amounts to an elegant theory suggesting that the sale of "marketable condition" gas at the leasehold represents a baseline, and that the costs of all further value-adding activities should be deductible. Under this view, producers explicitly condemn any distinction between marketing and transportation. But the argument in the end seems almost metaphysical; it is a claim that when the maximum value of gas can be realized by a downstream sale, then not only transportation costs but also the cost of efforts undertaken to identify and realize that value must somehow be more like transportation itself than they are like on-lease marketing.

Assuming arguendo that producers' metaphysical point is correct, we think it falls far short of compelling the Department to give up its usual distinction between marketing and transporting costs. Not only is the distinction traditional, *Walter Oil*, 111 IBLA at 265, but Interior has historically applied it to downstream sales, denying deductibility for a

lessee's costs in hiring a marketing agent to arrange transportation downstream, to aggregate customers, and to deal with a local distribution company. *Arco*, 112 IBLA at 9-12. Given the difficulty in slicing up marketing costs on the basis of the point of sale, and given that Interior must take administrability into account, compare Owen L. Anderson, "Royalty Valuation: Should Royalty Obligations Be Determined Intrinsically, Theoretically, or Realistically? (Part 2)," 37 Nat. Resources J. 611, 678 (1997) (discussing monitoring problems), we find nothing unreasonable in its hewing to the old line between marketing and transportation.

The producers' attack on Interior's denial of deductibility for aggregator/marketer fees, 30 C.F.R. §§ 206.157(g)(2), 206.177(g)(2), rests on the same foundations as the more general attack on "downstream" marketing costs and therefore fails for the same reasons. Intra-hub transfer fees, *id.* at §§ 206.157(g)(4), 206.177(g)(4), are slightly different. As IPAA recognizes, intra-hub transfer fees are charged "when [a] lessee *sells the gas* at [the] pipeline's junction at the hub." IPAA Br. at 30 (emphasis added). Interior distinguishes these fees, which are part of a "sales transaction," from so-called intra-hub wheeling fees, which are charged for the actual transportation of gas through a hub. See Final Rule, 62 Fed. Reg. at 65758. Producers contend that Interior allowed deduction for these costs in the past and failed to justify its change in policy. Before FERC Order No. 636, costs of this sort, even though reasonably classifiable as marketing, would have been bundled with transportation costs, making precise separation administratively troublesome, if not impossible. Once Order No. 636 unbundled rates and enabled Interior to identify

"nonallowable costs of marketing," Final Rule, 62 Fed. Reg. at 65755/1, it was reasonable for Interior to rigorously apply its conventional distinction between marketing and transportation.

Producers make two additional arguments regarding intrahub transfer fees. First, they seem to claim that Interior had the ability to "look behind" the bundled rates prior to 1997. But their citations to regulations governing deductions in the non-arms-length bargaining context, see 30 C.F.R. § 206.157(b)(2)(i) & (iii), offer little support. Indeed, they seem only to further demonstrate Interior's historical reluctance to separate actual transportation costs from "nonallowable costs of marketing" when such separation is administratively difficult. Second, they argue that intra-hub transfer fees are similar to other administrative costs, such as Gas Supply Realignment, Annual Charge Adjustment, and Gas Research Institute fees, which are deductible. Producers fail to note, however, that these are mandatory surcharges imposed by FERC on gas *transportation*, and thus, unlike intrahub transfer fees, can be considered part of the actual cost of transporting gas. See Final Rule, 62 Fed. Reg. at 65758.

"Unused" firm demand charges. Shippers of natural gas may choose among different degrees of assurance that space will be available for their shipments, paying (naturally) for extra security. By paying a firm demand charge (an upfront reservation fee), they secure a guaranteed amount of continuously available pipeline capacity; when they actually ship, they incur a "commodity charge" for the transport itself. The reservation fee, however, is nonrefundable — the cost of any reserved capacity that a lessee ultimately cannot use

will be lost unless it is able to resell the capacity. (Recall that the district court amended the summary judgment order, at the behest of the government, to provide for a credit to the government in the event of such resales.) In contrast, with "interruptible" service, shippers pay no reservation fee, but their access to pipeline capacity is subject to the changing needs of other, higher priority customers (i.e., those who pay for firm demand). Producers claim that the unused firm demand charges are part of their actual transportation costs, and thus should be deductible.

In defense of its contrary view, Interior said only that it does "not consider the amount paid for unused capacity as a transportation cost," Final Rule, 62 Fed. Reg. at 65757/1, not revealing to what category such expenses did belong. In its opening brief, it quotes its prior assertion and declares that the district court must be reversed because it "offered no cogent reason for rejecting this distinction." Interior Br. at 43. But Interior has offered no "distinction" at all, only an unusually raw ipse dixit. On its face, it is hard to see how money paid for assurance of secure transportation is not "for transportation"; the cost of freight insurance looks like a shipping expense, for example, even if the goods arrive without difficulty and the premium therefore goes "unused." And Interior makes no suggestion that producers have incurred such fees extravagantly — an extravagance that seems unlikely, as under the ordinary 1/8 lease the producer would bear 7/8 of the loss. Further, under the crediting arrangement provided by the district court order, the government will share in any recovery of the "unused" charge, a recovery that producers have strong incentives to pursue. While some reason may lurk behind the government's

position, it has offered none, and we have no basis for sustaining its conclusion. See, e.g., *Motor Vehicle Manufacturers Ass'n, Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983).

* * *

The judgment of the district court is reversed on all issues except for its ruling on unused firm demand charges, which we affirm.

So ordered.

Appendix A

SENTELLE, *Circuit Judge, concurring*: I join without reservation the conclusion of the court, and the reasoning that is essential to it. I find confusing, and indeed troubling, some of the discussion of the applicability of *Chevron* deference to the interpretation of statutes governing contracts in which the agency has a financial interest. I of course agree with the court's fundamental proposition that "the availability of *Chevron* deference depends on congressional intent. . . ." Maj. op. at 7. *Chevron* itself makes plain that the deference we afford an agency is created either by Congress "explicitly [leaving] a gap for the agency to fill," or implicitly delegating that authority to the agency by the decision of Congress not to directly address "the precise question at issue" while charging the agency with the administration and therefore the interpretation of the "ambiguous" act. *Chevron U.S.A. Inc. v. Natural Resources Defense Council*, 467 U.S. 837, 842-44 (1984). As the majority states, I "see no indication here of a special intent to withhold deference" in the interpretation of this act on a question as to which Congress has not spoken directly. Maj. op. at 8. I find neither persuasive nor necessary the court's reliance on interpretation of jurisdictional limitations as in *Oklahoma Natural Gas Co. v. FERC*, 28 F.3d 1281, 1283-84 (D.C. Cir. 1994). That case involves the very different question, to me a vexing one, of whether an ambiguity as to the limitations of agency authority constitutes the sort of implicit delegation upon which *Chevron* deference rests. Further, I do not understand the majority's proposition that "a general withdrawal of deference on the basis of agency self-interest might come close to overruling *Chevron*. . . ." Maj. op. at 7-8. We might as well propose that judges can sit on cases in which they have a financial interest because we regularly sit on cases on

which we might exercise self-aggrandizement by expansively interpreting our jurisdiction. Nonetheless, because this discussion is no more than dicta, and not at all essential to the court's conclusion, I concur in the decision reached and in the balance of the opinion.

APPENDIX B — AMENDED ORDER AND FINAL JUDGMENT OF THE UNITED STATES DISTRICT COURT FOR THE DISTRICT OF COLUMBIA DATED SEPTEMBER 1, 2000 AND FILED SEPTEMBER 6, 2000

UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF COLUMBIA

Civ. No. 98-00531 (RCL)

INDEPENDENT PETROLEUM
ASSOCIATION OF AMERICA,

Plaintiff,

v.

ROBERT L. ARMSTRONG, *et al.*,

Defendant.

(consolidated with)

Civ. No. 98-00631 (RCL)

AMERICAN PETROLEUM INSTITUTE,

Plaintiff,

v.

BRUCE BABBITT, *et al.*,

Defendants.

AMENDED ORDER AND FINAL JUDGMENT

Appendix B

Upon consideration of plaintiff American Petroleum Institute's and plaintiff Independent Petroleum Association of America's motion for summary judgment, defendants' cross-motion for summary judgment, the oppositions thereto, the record and the relevant law, and for the reasons set forth in the memorandum opinion issued March 28, 2000, it is hereby

ORDERED that plaintiffs' motions for summary judgment are GRANTED. The court hereby declares that the following regulations are unlawful and of no force or effect:

1. Those provisions of 30 C.F.R. §§ 206.152(i), 206.153(j), 206.157(g)(2), 206.157(g)(4), 206.157(g)(5), 206.172(i), and 206.173(i), 206.177(g)(2), 206.177(g)(4), 206.177(g)(5), to the extent that they impose a duty on lessees to market gas downstream at no cost to the lessor and disallow the deduction of downstream marketing costs.

2. Those provisions of 30 C.F.R. §§ 206.157(f)(1) and 206.177(f)(1) to the extent that they limit allowable costs for firm demand charges in determining transportation allowances to the applicable rate per MMBtu multiplied by the actual volumes transported; however, to the extent that a lessee sells unused firm capacity, and if the cost of that unused firm capacity was included in the previously reported transportation allowance, the lessee must amend its royalty report to reduce the transportation allowance by the revenue derived from the sale of the firm capacity and pay any resulting royalty and late payment interest due.

It is further

ORDERED that defendants are enjoined from implementing or enforcing those provisions of the above-referenced regulations found to be unlawful; and it is further

ORDERED that defendants' motion for summary judgment is DENIED.

Final judgment is hereby entered for the plaintiffs.

SO ORDERED.

DATE: 9-1-00

s/ Royce C. Lamberth
Royce C. Lamberth
United States District Court

APPENDIX C — OPINION OF THE UNITED STATES DISTRICT COURT FOR THE DISTRICT OF COLUMBIA DATED MARCH 28, 2000

United States District Court,
District of Columbia.

INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA, Plaintiff,

v.

Robert L. ARMSTRONG, et al., Defendant.
American Petroleum Institute, Plaintiff,

v.

Bruce Babbitt, et al., Defendants.

Nos. Civ. 98-00531 RCL, Civ. 98-00631 RCL.

March 28, 2000.

MEMORANDUM OPINION

LAMBERTH, District Judge.

Plaintiffs, two gas industry trade associations whose members hold federal and Indian gas leases, challenge as arbitrary, capricious and not in accordance with law amended Department of the Interior ("Interior") regulations ("Rule") that impose royalties on costs incurred when lessees sell gas in downstream markets. Plaintiffs contend that the royalty obligations imposed by the Rule exceed Interior's statutory

authority under the applicable statutes and have no basis in prior regulations or the gas leases themselves. Additionally, plaintiffs advance that the new Rule draws arbitrary distinctions between similar costs and impairs the obligations of leases executed prior to the enactment of the amendments. Defendants cross-move for summary judgment, asserting that the Rule was properly enacted after notice and comment and constitutes a reasonable interpretation of the regulations that Interior administers and the implied covenant of the gas leases. Upon consideration of the parties' cross-motions for summary judgment, the oppositions thereto, the record, oral argument, the applicable law, and for the reasons set forth below, the court GRANTS plaintiffs' motions for summary judgment and DENIES defendants' motion for summary judgment.

I. BACKGROUND

A. The Natural Gas Industry and Royalties on Federal and Indian Leases

The Department of the Interior issues and administers oil and gas leases for federal and Indian lands pursuant to the Mineral Leasing Act, 30 U.S.C. §§ 181-287, the Mineral Leasing Act for Acquired Lands, 30 U.S.C. §§ 351-359, Indian leasing statutes, 25 U.S.C. §§ 396a-396g, 25 U.S.C. § 396, and the Outer Continental Shelf Lands Act, 43 U.S.C. §§ 1331-1356. The leasing statutes and regulations administered by Interior require lessees to pay royalties on gas production from federal and Indian leases. These statutes provide that royalties are established by a specified percentage of the value of the gas saved, removed, or sold

from the lease. *See* 43 U.S.C. § 1337(a)(1); 30 U.S.C. § 226; 25 C.F.R. § 211.13; 25 U.S.C. § 212.16. Interior has the sole authority to "prescribe such rules and regulations as may be necessary to carry out" the leasing provisions. 43 U.S.C. § 1334(a); 30 U.S.C. § 189; 25 U.S.C. §§ 396 and 396(d). The Minerals Management Service ("MMS"), a bureau within Interior, collects, verifies and distributes revenues from the gas leases issued under these authorities.

The American Petroleum Institute ("API") is a nationwide trade association representing over 400 corporate members engaged in all aspects of petroleum exploration, production, refining, distribution, and marketing. API members hold oil and gas leases on federal and Indian lands. The Independent Petroleum Association of America ("IPAA") is a trade association representing more than 5,500 producers of oil and natural gas within the United States. Many IPAA members also hold leases on federal or Indian lands.

The present controversy grows out of the re-structuring of the gas pipeline industry brought about by Federal Energy Regulatory Commission Order No. 636. *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation; and Regulation of Natural Gas Pipelines After Partial Statutes and Regulations*, Order No. 636, 57 Fed. Reg. 13267 (April 16, 1992), FERC STATUTES AND REGULATIONS (CCH) ¶ 30, 950 (August 3, 1992); *order on reh'g*, Order No. 636-B, 57 Fed. Reg. 57911 (December 8, 1992), 61 F.E.R.C. (CCH) ¶ 61,272 (November 27, 1992). Accordingly, to appreciate the instant dispute, it is necessary to highlight lessees' obligations as they existed prior to the amended Rule and FERC Order 636.

Appendix C

In the pre-FERC 636 gas market, lessees sold gas to pipelines at or near the lease. Thus, the essential bargain embodied in federal and Indian leases entitled the lessor to a royalty based upon the value of production at the lease when the lessee produced gas from the leased premises. Consistent with this practice of selling gas at the lease, royalties on federal gas leases were typically "calculated at values at the wells, not at the pipe line destination. . . ." *Continental Oil Co. v. United States*, 184 F.2d 802, 820 (9th Cir. 1950). The basic rule on royalties, known as the "gross proceeds rule," provides that "under no circumstances shall the value of production for royalty purposes be less than the gross proceeds accruing to the lessee for the lease production." 30 C.F.R. § 206.152.(h) (1995). Gross proceeds are "the total monies and other consideration accruing to an oil and gas lessee for the disposition of [gas]," minus allowances or deductions. 30 C.F.R. § 206.151 (1995).

Under the pre-existing regulations and the leases, lessees also have an express duty to place gas in marketable condition, which means that production costs are borne solely by the lessee. The marketable condition rule requires lessees to produce "lease products which are sufficiently free from impurities and otherwise in a condition that they will be accepted by a purchaser under a sales contract typical for the field or area." 30 C.F.R. § 206.151 (1997).

In addition to the duty to place production in marketable condition, lessees have an express obligation to avoid waste. This duty can be satisfied by marketing and selling the gas at the lease or wellhead, or by beneficially consuming the production. *See, e.g.*, *California Co. v. Udall*, 296 F.2d 384,

387 (D.C. Cir. 1961) (construing 30 C.F.R. § 221.35 (now covered by 30 C.F.R. § 202.150(c)), which provided that a "lessee is obligated to prevent the waste of oil or gas and to avoid physical waste of the gas . . .").

Prior to FERC Order 636, producers generally did not need to incur transportation costs to locate a market for the gas, as pipelines were the primary purchasers. Accordingly, allowances for transportation costs were largely irrelevant. But when a lessee did transport gas, the lessee was required to pay a pipeline rate or tariff to transport the gas and Interior permitted the lessee to deduct the entire rate or tariff from the value it received downstream from the lease.

A producer likely sells gas away from the wellhead because it can demand a higher price in that market. Moving gas away from the wellhead to downstream markets, however, entails costs that are not incurred when gas is marketed at the lease. Thus, from an economic standpoint, the higher sale prices obtained in a downstream market are, in part, a reflection of the costs and risks involved. For example, a lessee transporting gas to a market downstream of the well will typically need to pay for the aggregation or storage of gas produced by multiple leases, in addition to the cost of getting the gas to the hub or sales point. Other fees involve the necessary costs of intermediaries such as market hub operators or for the management of market or environmental risks, or for scheduling delivery.

In the pre-FERC Order 636 gas market, all costs associated with moving gas to downstream markets were treated collectively as transportation costs and, hence, were

deductible from royalty value when the point of sale was downstream from the lease. That is, when downstream sales occurred, MMS would collect a royalty based on the enhanced value of production obtained in the downstream sale. Yet at the same time, MMS shared in the costs incurred by the lessee to transport the gas to the downstream market by tracing the value of production back to the lease or wellhead by deducting those costs associated with moving the gas downstream. Thus, while reaping the benefits of a higher value downstream sale through a higher royalty, MMS did not simply free-ride on the lessees' efforts to obtain value for the gas.

FERC Order 636 was designed to increase competition in the gas sales market by the mandatory unbundling of pipeline sales services. To that end, Order 636's unbundling mandate was directed at gas sales by *pipelines*, not producers, in order to facilitate gas purchases by suppliers other than the pipelines. It was thought that this unbundling would enable the development of more competitive markets for gas at the wellhead and downstream. FERC determined that without Order 636's unbundling, interstate pipelines would retain a substantial market advantage over alternative suppliers because pipelines included firm transportation service in their sales price and this more desirable capacity was reserved exclusively for pipelines' own sales customers. Firm transportation capacity was, therefore, unavailable to accommodate transactions between purchasers and alternative suppliers, and such sales were relegated to spot sales using interruptible transportation. In short, pipelines' bundling of sales and transportation precluded alternative suppliers from competing effectively in the premium firm,

long-term sales market because such suppliers were unable to offer transportation service on par with that offered by pipelines.

To correct this market imbalance, Order 636 required pipelines to convert their existing bundled sales contracts into contracts for an equivalent amount of firm transportation service. Under this arrangement, pipelines could sell gas at market-based rates, but these sales would now have to compete on equal footing with the sales of non-pipeline suppliers. Accordingly, even though FERC Order 636 had a substantial effect on the identity of gas purchasers from federal and Indian leases, it did not alter the fundamentals of gas sales transactions by gas *producers*, and thus, did not directly alter their obligations under federal and Indian gas leases.

B. The Instant Controversy

Four years after FERC issued Order 636, Interior decided to amend its regulations on gas royalties, purportedly as a response to the demands of the changed gas market. Accordingly, on July 31, 1996, the MMS issued a Notice of Proposed Rulemaking ("NOPR"). *Amendments to Transportation Allowance Regulations for Federal and Indian Leases to Specify Allowable Costs and Related Amendments for Gas Valuation Regulations*, 61 Fed. Reg. 39931 (July 31, 1996). Through this informal rulemaking, the MMS proposed to amend its regulations governing valuation for royalty purposes of gas produced from federal and Indian lands. The MMS stated that it was revising its regulations as a result of FERC Order No. 636, which required, *inter alia*, interstate gas pipelines to separate, or unbundle their sales services from their transportation services. Thus, the NOPR was billed as a

"clarification," which would "provide specific guidance to lessees and royalty payors" as to which transportation cost components were deductible for purposes of royalty valuation in the wake of FERC Order 636. NOPR, 61 Fed. Reg. 39,932. Specifically, MMS asserted that the unbundling achieved by FERC Order 636 now enabled MMS to isolate specific components of transportation costs that previously were not identifiable.

In addition to "clarifying" which cost allowances would be permitted after FERC Order 636, the NOPR also proposed to amend the product valuation regulations for natural gas to provide that federal lessees

> must place gas in marketable condition and market the gas for the mutual benefit of the lessee and the lessor at no cost to the Federal Government unless the lease agreement states otherwise. Where the value established under this section is determined by a lessee's gross proceeds, that value shall be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the costs of which ordinarily is the responsibility of the lessee to place the gas in marketable condition or market the gas.

NOPR at Sections 206.152(i) and 206.153(i). The same standard was proposed for Indian gas leases. NOPR at Sections 206.172(i) and 206.173(i). This proposed requirement amended the existing regulations, which had provided only that federal and Indian lessees had an obligation "to market the production for the mutual benefit of the lessee and the lessor" and to place

production "in marketable condition at no cost to the lessor." 30 C.F.R. §§ 206.152(b)(1)(iii); 206.152(i); 206.153(b)(1)(iii); 206.153(i); 206.173(b)(1)(iii); 206.172(i); 206.173(b)(1)(iii); 206.173(i). In addition to creating an express duty to market downstream at no cost to the lessor, the NOPR proposed to disallow deductions for marketing costs for aggregator or marketing services fees, Sections 206.157(g)(2) and 206.177(g)(2), as well as firm transportation demand charges[1] for unused capacity and intra-hub title transfer fees[2]. NOPR at Sections 206.157(f)(1); 206.177(f)(1); 206.157(g)(4); 206.177(g)(4). But at the same time, however, the NOPR proposed to continue allowing the deduction for transportation costs, which include gas supply realignment costs, Gas Research Institute fees, Annual Charge Adjustment fees, commodity charges,[3] wheeling costs[4], and long-term storage costs for gas stored over 30 days.

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1. To obtain firm transportation capacity on an interstate natural gas pipeline, a lessee must reserve the capacity and pay a reservation or so-called "demand" charge. This charge must be paid to the pipeline regardless of whether the lessee actually uses the reserved capacity. Under the proposed Rule, the deductible portion of these charges would be limited to the applicable rate multiplied by the actual volumes transported. NOPR Sections 206.157(f)(1).

2. Intra-hub title transfer fees are paid to operators of gas pipeline hubs for services relating to accounting for the sale of gas at the hub.

3. Commodity charges are fees assessed by pipelines to cover the variable costs of pipeline operation.

4. Wheeling costs are fees charged by a hub operator to move gas through a market center or hub.

Appendix C

During notice and comment, plaintiffs filed objections to the proposed Rule, including the provision quoted above that creates an express duty on lessees to market the gas at no cost to the federal government and the proposed provisions disallowing "marketing" cost deductions. Upon conclusion of the notice and comment period, the MMS issued its final rule on December 16, 1997, which became effective on February 1, 1998. 62 Fed. Reg. 65753 (December 16, 1997). Plaintiffs' members holding federal and Indian gas leases are presently subject to the Rule.

The final rule adopted all of the provisions contained in the NOPR, except that the provision creating an express duty to market downstream at no cost to the federal government no longer contained the phrase "unless the lease agreement states otherwise." In adopting the terms of the NOPR, MMS again stated that

> [The Rule] is necessary because components previously aggregated and unidentifiable may now be separately identified in transportation contracts, and new costs unique to the FERC Order 636 environment are emerging.
>
> Further, some of the components reflect non-deductible costs of marketing rather than transportation.

Id. at 65753. The MMS also stated that lessees have the obligation "to incur all marketing costs." *Id.* at 65756. MMS acknowledges that the Rule represents a departure from prior practice by noting that the Rule will reduce deductions from royalties because "lessees will not be able to deduct these previously bundled marketing costs." *Id.* at 65755.

Appendix C

The dispute in this matter centers on the Rule's effect on lessees' royalty obligations when they sell gas downstream of the lease. Simply stated, plaintiffs object to the Rule because certain downstream costs (now labeled by MMS as "marketing costs") previously deductible from royalty value are no longer deductible. The end result of the Rule is that lessees must now pay a royalty in excess of the value of production they received from the sale. In attacking the Rule as arbitrary and capricious, plaintiffs present a host of specific challenges. Foremost, plaintiffs dispute MMS' suggestion that the Rule changes nothing because an implied covenant to market at no cost previously existed in the current leases. They further maintain that the Rule's express duty to market contradicts the pre-existing contractual obligations and rights under leases executed prior to the Rule's effective date. In addition to improperly imposing a duty to market downstream at no cost, plaintiffs argue that the Rule is invalid because MMS now disallows the deduction of downstream marketing costs from the royalty value, costs which were previously deductible. And, finally, plaintiffs assert that in treating "marketing" and "transportation" costs differently, MMS draws improper arbitrary distinctions between similar costs. On these grounds, plaintiffs seek declaratory and injunctive relief as to those portions of the Rule found to be contrary to statute, arbitrary and capricious, an abuse of discretion, and contrary to the terms of pre-existing leases.

By contrast, defendants maintain that disallowing deductions for downstream marketing costs is merely a continuation of longstanding agency policy and practice because lessees have always have had a duty to market at no cost, a duty which MMS contends is implied in the gas leases

and certain prior regulations. In their cross-motion for summary judgment, defendants maintain that the Rule is entitled to deference as it manifests a reasonable exercise of Interior's authority to define the "value" of gas production for royalty purposes. Defendants assert that the applicable statutes are silent on the issue of value for royalty purposes, and thus, according to defendants, the only question for the court is whether, when viewed through the deferential prism of *Chevron U.S.A. v. Natural Resources Defense Council*, 467 U.S. 837, 844, 104 S. Ct. 2778, 81 L. Ed. 2d 694 (1984), the amended Rule is a reasonable way to state value for royalty purposes. In the Rule, MMS states that it "reviewed [the] current gas transportation regulations (30 C.F.R. § 206.156; 206.157; 206.176; 206.177 (1996)) and determined that they provide general authority to calculate transportation deductions for cost components resulting from implementing FERC Order 636 and previous FERC orders." 62 Fed. Reg. 65753. And, with respect to the duty to market at no cost, MMS concedes that "the obligation to place production in marketable condition is legally distinct from the issue of marketing the gas." *Id.* Instead, MMS asserts that "the implied covenant of the lease dictates that lessees must market production at no cost to the lessor." MMS then states that "[b]oth principles [the duty to place gas in marketable condition and the duty to market at no cost] are expressly stated in the March 1, 1988, gas regulations at 30 C.F.R. §§ 206.151 and 202.151." 62 Fed. Reg. 65756. More specifically, 30 C.F.R. § 206.151 states that "marketable condition means lease products which are sufficiently free from impurities and otherwise in a condition that they will be accepted by a purchaser under a sales contract typical for the field or area." And, 30 C.F.R. § 202.151 provides, in

relevant part, "[a] reasonable amount of residue gas shall be allowed royalty free for operation of the processing plant, but no allowance shall be made for boosting residue gas or other expenses incidental to marketing, except as provided in 30 C.F.R. § 206."

II. DISCUSSION

Where a controversy presents no genuine issue as to any material fact, summary judgment is appropriate and the moving party is entitled to judgment as a matter of law. Fed. R. Civ. P. 56(c); *FDIC v. Bender*, 127 F.3d 58, 63 (D.C. Cir. 1997); *Diamond v. Atwood*, 43 F.3d 1538, 1540 (D.C. Cir. 1995). In the present matter, plaintiffs do not dispute that when they sell gas at the lease or wellhead, they must bear the costs of placing gas in marketable condition through proper conditioning or processing. This duty is imposed on lessees through the marketable condition rule, which the parties agree is legally distinct from a duty to market gas downstream at no cost. As such, to the extent that getting gas into a suitable physical condition for sale constitutes "marketing" for purposes of selling gas at the lease, plaintiffs acknowledge that when they sell gas *at the lease*, they may not deduct these "marketing" costs from royalty value by virtue of the marketable condition rule. Similarly, Interior does not contend that plaintiffs have an obligation to sell gas downstream off the lease. In other words, Interior concedes that plaintiffs are free to sell or beneficially consume gas at the wellhead only, rather than pursue downstream sales. Finally, Interior acknowledges, and the court finds as a matter of fact, that the downstream marketing costs made non-deductible by the Rule, were, in fact,

previously deducted by plaintiffs. *See* 62 Fed. Reg. 65755 (noting that the Rule will reduce deductions from royalties because "lessees will not be able to deduct these previously bundled marketing costs"). Thus, no genuine issue of material fact precludes the court from disposing of this matter on summary judgment.

Under the Administrative Procedure Act, courts must set aside agency action found to be "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." 5 U.S.C. § 706(2)(A). Thus, to sustain its actions, an agency must articulate a satisfactory explanation for its action and a rational connection between the facts found and the choice made. *Motor Vehicle Mfgrs. Ass'n v. State Farm Mutual Auto. Ins. Co.*, 463 U.S. 29, 43, 103 S. Ct. 2856, 77 L. Ed. 2d 443 (1983). An agency's duty to explain is paramount, and "belated attempts by counsel to provide a basis for [the agency's] choices cannot substitute for a sufficient record." *National Welfare Rights Org. v. Mathews*, 533 F.2d 637, 638-39 (D.C. Cir. 1976). Similarly, where an agency changes a settled course of behavior or departs from prior policy, the agency is obligated to provide in the record a reasoned analysis for the change. *Motor Vehicle Mfgrs. Ass'n*, 463 U.S. at 42, 103 S. Ct. 2856; *see also Greater Boston Television Corp. v. FCC*, 444 F.2d 841, 852 (D.C. Cir. 1970) (stating that "an agency changing its course must supply a reasoned analysis indicating that prior policies and standards are being deliberately changed, not casually ignored, and if an agency glosses over or swerves from prior precedents without discussion it may cross the line from the tolerably terse to the intolerably mute").

Appendix C

In all its actions, an agency is constrained by the statutory authority given by Congress. Thus, where Congress has spoken to a particular matter, Congress' plainly expressed intent governs. *Independent Petroleum Ass'n of America v. Babbitt*, 92 F.3d 1248, 1255 (D.C. Cir. 1996) (citing *Chevron U.S.A. v. Natural Resources Defense Council*, 467 U.S. 837, 844, 104 S. Ct. 2778, 81 L. Ed. 2d 694 (1984)). But where a statute is silent or ambiguous with respect to a specific issue, a court must defer to the interpretation advanced by the agency that administers the statute, provided that the proffered interpretation is reasonable. *Id.* Judicial review of an agency's interpretation of its regulations follows a similar standard, which also examines the reasonableness of the interpretation. *Enron Oil & Gas Co. v. Lujan*, 978 F.2d 212, 215 (5th Cir. 1992).

As the D.C. Circuit has recognized, "*Chevron* review and arbitrary and capricious review overlap at the margins." *Independent Petroleum*, 92 F.3d at 1258. That is, in certain cases, "the two analytic frameworks . . . produce the same result." *Id.* The present dispute is such a case. As such, a determination that Interior acted arbitrarily and capriciously by imposing on lessees a duty to market downstream at no cost to the lessor is the functional equivalent of finding that the agency's interpretation of the regulations and the lease forms to contain an implied duty to market at no cost is unreasonable.

A court interpreting the terms of a government contract must examine its express terms. Thus, unlike the more solicitous standards of review under the Administrative Procedures Act, if the terms of a government contract are

ambiguous, under the *contra proferentem* doctrine, courts will interpret them against the government as the drafter of the contract. *United States v. Seckinger*, 397 U.S. 203, 210, 90 S. Ct. 880, 25 L. Ed. 2d 224 (1970). Indeed, no deference is due an agency's interpretation of contracts in which it has a proprietary interest. *Lockheed Martin IR Imaging Sys. Inc. v. West*, 108 F.3d 319, 322 (Fed. Cir. 1997); *Mesa Air Group Inc. v. Dep't of Transp.*, 87 F.3d 498, 508 (D.C. Cir. 1996). Similarly, an agency's interpretation of its own regulations is not entitled to deference when it will affect contracts to which the agency is a party. *Transohio Sav. Bank v. Director, Office of Thrift Supervision*, 967 F.2d 598, 614 (D.C. Cir. 1992).

In light of these standards, the starting point for this court's review of the validity of the Rule must begin with the relevant governing statutes. As noted above, Interior administers gas leases for federal and Indian lands pursuant to the Mineral Leasing Act, 30 U.S.C. §§ 181-287, the Mineral Leasing Act for Acquired Lands, 30 U.S.C. §§ 351-359, Indian leasing statutes, 25 U.S.C. §§ 396a-396g, 25 U.S.C. § 396, and the Outer Continental Shelf Lands Act, 43 U.S.C. §§ 1331-1356. These statutes require lessees to pay royalties on the value of gas production from federal and Indian leases. By statute, Interior has broad discretion to "prescribe such rules and regulations as may be necessary to carry out" the leasing provisions. 43 U.S.C. § 1334(a); 30 U.S.C. § 189; 25 U.S.C. §§ 396 and 396(d). Defendants contend that the Rule at issue is a proper exercise of this discretion and that the Secretary may decide what will be considered in calculating "value" for purposes of royalty valuation.

To begin with, this construction overlooks important limiting language in the statutes with respect to royalty value. That is, the relevant statutes limit the collection of royalties to "the value of production saved, removed or sold from the lease." For example, under the Outer Continental Shelf Lands Act, which governs offshore leases, the MMS may grant leases obligating lessees to pay royalties on "the amount or value of production saved, removed, or sold" from the lease. 43 U.S.C. §§ 1335(a)(8); 1337(a) and 1337(b)(3). Similarly, under the Minerals Leasing Act, the MMS may grant leases conditioned on payment of royalties "in amount or value of the production removed or sold from the lease." 30 U.S.C. § 226(b)(1)(A). This "value of production" standard is equally applicable to Indian leases. 25 U.S.C. § 396.

The longstanding interpretation of "value of production," one recognized by Interior (at least until the present matter) and affirmed by the courts, is that it refers to the value of oil or gas *at the wells*. *See United States v. General Petroleum*, 73 F. Supp. 225, 235 (S.D. Cal. 1946), *aff'd sub nom Continental Oil Co. v. United States*, 184 F.2d 802, 820 (9th Cir. 1950). Thus, it is well-recognized that the government's royalty interest is limited to the value of production at the lease or wellhead, not in value enhancements resulting from downstream activities. *Marathon Oil Co. v. United States*, 604 F. Supp. 1375 (D. Alaska 1985). Accordingly, the government's royalty interest on the value of production may not include proceeds received by lessees that are attributable to matters other than gas production. *Diamond Shamrock Exploration Co. v. Hodel*, 853 F.2d 1159, 1165 (5th Cir. 1988). *Cf. Independent Petroleum*, 92 F.3d at 1252. In light of these established principles, the court finds untenable

MMS' present position that it has the authority to define value to include downstream costs unrelated to production of the gas. MMS offers no reasoned basis justifying this departure in the Rule. The court finds that the Rule does not afford a sufficient explanation as to why FERC Order 636 mandates imposing these expanded duties on producers, particularly when the primary regulatory effects of that order were directed at pipelines. Rather, MMS merely asserts that the FERC order "unbundles" marketing costs and marketing costs are not deductible.

In addition to assessing whether the relevant statutes speak to the issue of royalty valuation, the court must also look to the regulations MMS interpreted in promulgating the Rule. Here again, the court must analyze the specific provisions in light of the reasoning set forth in the Rule itself, not the *post hoc* justifications put forward by defendants' counsel. As noted above, MMS concedes in the Rule that the marketable condition rule does not provide the legal basis for its assertion of a duty to market downstream at no cost. *See* 62 Fed. Reg. 65753 ("We recognize that the obligation to place production in marketable condition is *legally distinct* from the issue of marketing the gas."). Instead, MMS claims authority for the Rule by virtue of the implied covenant of gas leases and a provision of a prior regulation concerning royalties on processed gas at 30 C.F.R. § 202.151. And, as general authority to determine transportation deductions, MMS points to several provisions of prior regulations pertaining to transportation allowances. (30 C.F.R. §§ 206.156; 206.157; 206.176; 206.177 (1996)).

As support for its position that lessees have a duty to market downstream at no cost, MMS points to a provision

in the regulation dealing with royalties on processed gas. This provision provides, in relevant part, that "[a] reasonable amount of residue gas shall be allowed royalty free for operation of the processing plant, but no allowance shall be made for boosting residue gas or other expenses incidental to marketing, except as provided in 30 C.F.R. § 206." 30 C.F.R. § 202.151. While according appropriate deference to an agency's reasonable interpretation of its own regulations, courts must view such interpretations with skepticism when they affect contracts to which the agency is a party. *Transohio Sav. Bank v. Director, Office of Thrift Supervision*, 967 F.2d 598, 614 (D.C. Cir. 1992); *see also Mesa Air Group, Inc. v. Department of Transportation*, 87 F.3d 498, 505-506 (D.C. Cir. 1996) (noting that principle of *contra proferentem* would compel finding that Department of Transportation's interpretation of its own agreements provided "no logical stopping point" and was therefore unreasonable). As authority for the imposition of a broad-reaching duty to market gas production at no cost, the court finds MMS' reliance on this single provision, read out of context, to be unpersuasive. Quite simply, the court finds it unreasonable to infer a duty of general applicability from an isolated provision pertaining to production costs for processed residue gas. Moreover, the regulation itself demonstrates that it is intended as an application of the general duty to place gas into marketable condition, a duty which involves production-related activities at the wellhead. Boosting is a process that restores pressure lost during manufacturing. This restored pressure puts the gas into a condition where it can be delivered to a purchaser. Thus, as MMS concedes in its comments in the 1988 regulations, boosting and other incidental marketing expenses referred

to in this provision are costs associated with placing gas in marketable condition, an obligation that is "legally distinct" from the duty to market gas at no cost. *See* 53 Fed. Reg. at 1236 (stating that "the cost for boosting residue gas is considered as a cost necessary to place the gas in marketable condition"). Finally, MMS' assertions regarding this provision are undermined by the fact that the provision plainly suggests the opposite conclusion than the one MMS advances. Specifically, the provision's concluding restrictive clause, which provides "except as provided in 30 C.F.R. Part 206," would be superfluous if marketing costs were not otherwise deductible. *See* 30 C.F.R. § 202.151. In sum, the court finds that MMS' reading of this provision, in isolation and out of context presents an unreasonable interpretation of the regulation. MMS fails to articulate a rational basis as to why a duty to market downstream at no cost flows naturally from a provision that, on its face, deals only with placing the gas in marketable condition (a production-related duty) and which suggests that marketing costs may be allowed under the regulations. Moreover, this conclusion is buttressed by reference to the regulations as a whole, which set forth extensive detail concerning the duties of lessees with respect to royalties. Given the level of detail in the regulations, one would expect them to make more than a cryptic, oblique reference to create such a far-reaching obligation.

The court also finds that MMS' distinctions between what it now labels as "marketing" costs and "transportation" costs are not reasonably suggested by the text of the provisions governing allowances. Moreover, the arbitrary distinctions that MMS draws between the two costs result in inconsistencies, which MMS fails to explain in the Rule.

Cf. Independent Petroleum v. Babbitt, 92 F.3d at 1260. For example, under the Rule, MMS permits an allowance for intra-hub wheeling costs, reasoning that such costs are "actual" costs of transportation. At the same time, however, MMS rejects the deductibility of intra-hub transfer fees on the basis that they are not "actual" costs, merely "administrative" costs of transportation. Similarly, MMS provides no reasoned basis — aside from conclusory statements — for disallowing aggregator/marketer fees. 62 Fed. Reg. 65759, 67762-64. Aggregation of gas from multiple leases at a specific place and time directly implicates the movement of multiple gas streams. Yet MMS provides no explanation of why it does not consider such costs to be actual, reasonable costs of transporting gas. MMS also disallows a deduction for firm demand charges for unused capacity, stating that it does not "consider the amount paid for unused capacity as a transportation cost." 62 Fed. Reg. 65757. MMS simply asserts that because this portion of capacity was not ultimately used to move the gas, it is not an "actual" cost of transporting gas.

By comparison, the Rule maintains allowances for other costs under the umbrella of "transportation costs," even though these costs do not involve moving the gas. For instance, Gas Research Institute fees are required to be paid to that entity to fund research on issues pertinent to the gas industry. Likewise, Annual Charge Adjustment fees are administrative in nature, and yet are still deductible. And, finally, under the Rule storage fees for holding gas more than 30 days remain deductible, while gas held for 30 days or less is not deductible. In short, MMS simply labels certain costs marketing and certain costs transportation, without offering any consistent or principled justification for why a particular label applies.

Appendix C

In addition to prior regulations, MMS also premises its disallowance of downstream marketing cost deductions on an implied covenant of the gas leases. Specifically, MMS maintains that, under the leases, lessees have an implied duty to market gas at no cost to the lessor. *See* 62 Fed. Reg. 65756 (claiming that implied covenant of lease "dictate[s] that lessees must market production at no cost to the lessor"). MMS reasons that, by virtue of this covenant, marketing costs have always been borne by lessees, so that requiring lessees to bear these costs in downstream markets does not effect a substantive change of the lessees obligations under the leases. *See* 62 Fed. Reg. 65760 (stating that MMS does not have express statutory authority to implement a retroactive effective date for this rule but contending that MMS "disagree[s] that this is a substantive rule that changes or increases our existing authority and policies"). As such, MMS contends that the new language in the Rule creating an express duty to market at no cost merely clarifies the concept already embodied in "the implied covenant to market for the mutual benefit of Federal and Indian oil and gas lessees and lessors." 62 Fed. Reg. 65756. Thus, MMS invites the court to review the leases.

In certain instances, an agency's interpretation of contracts may be entitled to deference. *See, e.g., National Fuel Gas Supply Corp. v. FERC*, 811 F.2d 1563, 1570 (D.C. Cir. 1987). But to be valid, such interpretations must be reasonable. Moreover, deference to an agency interpretation of a contract may be inappropriate where an agency has a proprietary interest in the contract. *Lockheed Martin IR Imaging Sys. Inc. v. West*, 108 F.3d 319, 322 (Fed. Cir. 1997); *Mesa Air Group Inc. v. Dep't of Transp.*, 87 F.3d 498, 508

(D.C. Cir. 1996). And, where the government drafts the terms of the contract, on a take-it-or-leave-it basis, the terms of such contracts will be construed strictly against the drafter. *See, e.g., Leo Sheep Co. v. United States*, 440 U.S. 668, 668, 99 S. Ct. 1403, 59 L. Ed. 2d 677 (1979) (declining to find an implied easement in favor of the government when not explicitly provided for in railroad land grants).

The court begins by noting its skepticism as to the existence of an implied covenant to market at no cost in the leases, for if such an implied duty were so widely recognized and longstanding, common sense suggests that there would be no need to write it in at this late date. Indeed, MMS' recognition that costs now disallowed by the Rule were previously being deducted by producers undercuts its assertion that producers have always been aware that such costs were not allowable by virtue of an implied covenant in the leases. Moreover, the court hesitates to endorse an agency's proffered interpretation of a contract in which it has a proprietary interest, particularly where, as here, the interpretation greatly expands the obligations of the private party to the direct benefit of the government.

The court has reviewed the express terms of various federal and Indian gas lease forms and finds that they do not support MMS' contention that federal gas leases contain an implied covenant to market gas at no cost. Moreover, MMS has failed to direct the court to any language or particular provision in the lease forms that supports its position that a duty to market at no cost was contemplated by the parties at the time of execution of the leases. To the contrary, the court finds that the express terms of the leases lead to the opposite

conclusion by imposing certain affirmative duties on lessee and reserving correlative rights in the lessor. Quite simply, a duty to market gas at no cost may not be reasonably implied from the four corners of the lease agreements.

For example, Form 5-157, issued for oil and gas mining on tribal Indian lands, repeats the statutory mandate that royalties are to be calculated on the basis of the value of production. Form 5-157(c), at 2. In addition, the lease creates a number of express duties on the lessees, which include the duty "to exercise reasonable diligence in drilling and operating wells for oil and gas on the lands covered hereby" and "to carry *out at the expense of the lessee* all reasonable orders and requirements of the oil and gas supervisor relative to *prevention of waste, and preservation of property and the health and safety of workmen.*" *Id.* (emphasis added). The court finds that these two provisions do not support MMS' position with respect to an implied duty to market at no cost. Rather, lessees' duty to assume all costs in this provision is limited to costs related to waste prevention and health and safety, and makes no suggestion of a similar duty to market. In addition, the duty of diligence is framed in terms of production related matters, such as drilling and well operation, not sales or marketing. Given the express language of the lease form, clearly spelling out the obligations of the lessee, the court declines to imply an additional duty not expressly stated or even suggested by the actual terms of the agreement.

Similarly, Form 154h, another lease form covering allotted Indian lands, also limits the applicable royalty value, stating that " 'value' for the purposes [of royalties] may, in

the discretion of the Secretary, be calculated on the basis of the highest price paid or offered *at the time of production*. . . ." Form 154h(c). This lease form also enumerates lessees' duties to include "diligence in drilling and operating wells" and "to carry out at the expense of the lessee all reasonable orders and requirements . . . relative to prevention of waste, and preservation of property and the health and safety of workmen." Form 154h(f). These duties on the lessee are mirrored in the form's language regarding rights of the lessor, which reserve to the Secretary the power to impose restrictions "as to time or times for drilling of wells and as to the production from any well . . . when in his judgment such action may be necessary or proper for the protection of natural resources of the leased land." Form 154h(9).

Form 436A, a lease form for oil and gas leases on federal lands, imposes a number of express duties on the lessee, but the court finds that this form fails to include any textual support for a broad-based duty to market at no cost. Form 436A(3). Notably, the express duties imposed on lessees concern operations at the well, such as drilling and production. There is no mention of obligations relating to sale or marketing. And, with respect to lessee's royalty obligations, the form provides, *inter alia*, that "in no event may 'value' for the purposes of this lease be less than the fair market value *of the production.*" Form 436A(C) (emphasis added).

The court also cannot find support for an implied covenant to market at no cost in another gas lease form for lands covered by the Mineral Leasing Act, Form 3100-11.

Appendix C

This form begins by stating that the lease may be subject to future laws and regulations "when not inconsistent with lease rights granted or specific provisions of this lease." Form 3100-11. The lease goes on to provide that royalties "shall be computed in accordance with regulations on production removed or sold." Form 3100-11 at Sec. 2. Section 4 of the lease obligates lessee "to exercise reasonable diligence in developing and producing, and shall prevent unnecessary damage to the loss of or waste of leased resources." The lease also imposes certain recordkeeping obligations on lessees. Form 3100-11 at Sec. 5.

Similarly, the court finds that Outer Continental Shelf Lands Act lease forms also do not contain terms or obligations that support an implied covenant to market at no cost. To begin with, Form 3380-1 opens with a preamble which states that the lease shall be subject to "all lawful and reasonable regulations of the Secretary of the Interior *when not inconsistent with any express and specific provisions herein.*" The form then goes on to provide that lessee have the obligation to pay "royalty on production," in the "amount or value of production saved, removed or sold from the leased area." In addition, the OCSLA forms impose express duties on the lessee regarding operation of the wells. Thus, like the Indian lease forms, the OCSLA forms impose a duty of diligence concerning "drilling and producing." While the OCSLA forms do provide that the Secretary may establish "reasonable minimum values for purposes of computing royalty on products obtained from the lease," the same provision interjects the statutory limitation "value of production." Moreover, the section addressing "Reservations to the Lessor," contains a corollary provision entitled "taking of royalties," which expressly limits royalties to "the amount or value of production."

Appendix C

In sum, having reviewed the applicable lease forms, the court finds no reasonable support for MMS' position that the leases obligate lessees to market gas at no cost to the lessor. To the contrary, the lease forms enumerate the various production- and royalty-related duties and rights without any mention of marketing or sale of gas beyond the lease or wellhead. Had the parties contemplated such an expanded duty when the contract was formed, it is likely that they would have expressly addressed it in the leases. Here, the doctrine of *contra proferentem*

> puts the risk of ambiguity, lack of clarity, and absence of proper warning on the drafting party which could have forestalled the controversy; it pushes the drafters toward improving contractual forms; and its saves contractors from hidden traps not of their own making.

Sturm v. United States, 190 Ct. Cl. 691, 421 F.2d 723, 727 (1970). Thus, having examined the terms of the lease forms, the court finds that a duty to market at no cost does not rise by natural implication from these agreements.

Nor can MMS rely on the fact that the lease forms provide that the leases shall be subject to future regulations. Rather, in so providing, the lease forms uniformly limit the application of future regulations to those that are consistent with the express terms of the lease or that do not alter the rate of royalty. As explained above, the court finds that an implied duty to market downstream is not consistent with the terms of the existing leases.

Appendix C

As the Court of Appeals for the District of Columbia Circuit has instructed, deference to an agency's interpretation is dangerous where it abrogates existing contracts and leads "a court to endorse self-serving views that an agency might offer in post hoc reinterpretation of its contract[s]." *Transohio*, 967 F.2d at 614. The present matter warrants this court's apprehension. Quite simply, upholding the Rule by endorsing MMS' interpretation of the leases and regulations would place no logical limits on MMS' authority to rewrite the leases to the detriment of the lessees and the direct pecuniary benefit of the government. *Cf. Mesa Air Group*, 87 F.3d at 505-06.

III. CONCLUSION

For the reasons set forth above, the court hereby finds that the Rule amending the regulations governing royalty valuation on federal and Indian gas leases, to the extent that it imposes a duty on lessees to market gas downstream at no cost to the lessor and disallows the deduction of downstream "marketing" costs, is invalid. Likewise, the court finds that the application of the Rule to leases executed prior to the regulation is improper, as it contravenes the rights and obligations of set forth in the express terms of the leases.

A separate opinion shall issue this date.

Appendix C

ORDER AND FINAL JUDGMENT

Upon consideration of plaintiff American Petroleum Institute's and plaintiff Independent Petroleum Association of America's motions for summary judgment, defendants' cross-motion for summary judgment, the oppositions thereto, the record and the relevant law, and for the reasons set forth in the memorandum opinion issued today, it is hereby

ORDERED that plaintiffs' motions for summary judgment are GRANTED. The court hereby declares that the following regulations are unlawful and of no force or effect: 30 C.F.R. §§ 206.152(i); 206.153(i); 206.157(f)(1); 206.157(g)(2); 206.157(g)(4); 206.157(g)(5); 206.172(i); 206.173(i); 206.177(f)(1); 206.177(g)(2); 206.177(g)(4); and 206.177(g)(5); and it is further

ORDERED that defendants are enjoined from implementing or enforcing the above-referenced regulations; and it is further

ORDERED that defendants' motion for summary judgment is DENIED.

Final Judgment is hereby entered for plaintiffs.

SO ORDERED.

APPENDIX D — ORDER OF THE UNITED STATES COURT OF APPEALS FOR THE DISTRICT OF COLUMBIA CIRCUIT DENYING PETITION FOR REHEARING (FILED BY INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA) DATED AND FILED JUNE 21, 2002

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

September Term, 2001
98cv00531
98cv00631

Filed On: June 21, 2002 [685093]

No. 00-5404

Independent Petroleum Association of America,

Appellee

v.

Wallace P. DeWitt, Acting Assistant Secretary, for Land and Minerals Management, DOI and United States Department of the Interior,

Appellants

Consolidated with 00-5405

Appendix D

BEFORE: Ginsburg, Chief Judge, and Edwards, Sentelle, Henderson, Randolph,* Rogers, Tatel, and Garland,* Circuit Judges; and Williams, Senior Circuit Judge

ORDER

Upon consideration of appellee Independent Petroleum Association of America's petition for rehearing en banc, the response thereto, and the absence of a request by any member of the court for a vote, it is

ORDERED that the petition be denied.

Per Curiam

FOR THE COURT:
Mark J. Langer, Clerk

BY:
Michael C. McGrail
Deputy Clerk

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* Circuit Judges Randolph and Garland did not participate in this matter.

APPENDIX E — ORDER OF THE UNITED STATES COURT OF APPEALS FOR THE DISTRICT OF COLUMBIA CIRCUIT DENYING PETITION FOR REHEARING (FILED BY AMERICAN PETROLEUM INSTITUTE) DATED AND FILED JUNE 21, 2002

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

September Term, 2001
98cv00531
98cv00631

Filed On: June 21, 2002 [685088]

No. 00-5404

Independent Petroleum Association of America,

Appellee

v.

Wallace P. DeWitt, Acting Assistant Secretary, for Land and Minerals Management, DOI and United States Department of the Interior,

Appellants

Consolidated with 00-5405

Appendix E

BEFORE: Ginsburg, Chief Judge, and Edwards, Sentelle, Henderson, Randolph,* Rogers, Tatel, and Garland,* Circuit Judges; and Williams, Senior Circuit Judge

ORDER

Upon consideration of appellee American Petroleum Institute's petition for rehearing en banc, and the absence of a request by any member of the court for a vote, it is

ORDERED that the petition be denied.

Per Curiam

FOR THE COURT:
Mark J. Langer, Clerk

BY:
Michael C. McGrail
Deputy Clerk

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* Circuit Judges Randolph and Garland did not participate in this matter.

APPENDIX F — RELEVANT STATUTES

MINERAL LEASING ACT

30 U.S.C. § 226(a)-(c):

§ 226. Lease of oil and gas lands

(a) Authority of Secretary

All lands subject to disposition under this chapter which are known or believed to contain oil or gas deposits may be leased by the Secretary.

(b) Lands within known geologic structure of a producing oil or gas field; lands within special tar sand areas; competitive bidding; royalties

(1)(A) All lands to be leased which are not subject to leasing under paragraphs (2) and (3) of this subsection shall be leased as provided in this paragraph to the highest responsible qualified bidder by competitive bidding under general regulations in units of not more than 2,560 acres, except in Alaska, where units shall be not more than 5,760 acres. Such units shall be as nearly compact as possible. Lease sales shall be conducted by oral bidding. Lease sales shall be held for each State where eligible lands are available at least quarterly and more frequently if the Secretary of the Interior determines such sales are necessary. A lease shall be conditioned upon the payment of a royalty at a rate of not less than 12.5 percent in amount or value of the production

removed or sold from the lease. The Secretary shall accept the highest bid from a responsible qualified bidder which is equal to or greater than the national minimum acceptable bid, without evaluation of the value of the lands proposed for lease. Leases shall be issued within 60 days following payment by the successful bidder of the remainder of the bonus bid, if any, and the annual rental for the first lease year. All bids for less than the national minimum acceptable bid shall be rejected. Lands for which no bids are received or for which the highest bid is less than the national minimum acceptable bid shall be offered promptly within 30 days for leasing under subsection (c) of this section and shall remain available for leasing for a period of 2 years after the competitive lease sale.

(B) The national minimum acceptable bid shall be $2 per acre for a period of 2 years from December 22, 1987. Thereafter, the Secretary may establish by regulation a higher national minimum acceptable bid for all leases based upon a finding that such action is necessary: (i) to enhance financial returns to the United States; and (ii) to promote more efficient management of oil and gas resources on Federal lands. Ninety days before the Secretary makes any change in the national minimum acceptable bid, the Secretary shall notify the Committee on Natural Resources of the United States House of Representatives and the Committee on Energy and Natural Resources

of the United States Senate. The proposal or promulgation of any regulation to establish a national minimum acceptable bid shall not be considered a major Federal action subject to the requirements of section 4332(2)(C) of title 42.

(2) If the lands to be leased are within a special tar sand area, they shall be leased to the highest responsible qualified bidder by competitive bidding under general regulations in units of not more than five thousand one hundred and twenty acres, which shall be as nearly compact as possible, upon the payment by the lessee of such bonus as may be accepted by the Secretary. Royalty shall be 12 1/2 per centum in amount or value of production removed or sold from the lease, subject to subsection (k)(1)(c)[1] of this section. The Secretary may lease such additional lands in special tar sand areas as may be required in support of any operations necessary for the recovery of tar sands.

(3)(A) If the United States held a vested future interest in a mineral estate that, immediately prior to becoming a vested present interest, was subject to a lease under which oil or gas was being produced, or had a well capable of producing, in paying quantities at an annual average production volume per well per day of either not more than 15 barrels per day of oil or condensate, or not more than 60,000 cubic feet of gas, the holder of the lease may elect to continue the lease as a noncompetitive lease under subsection (c)(1) of this section.

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1. So in original. Probably should be subsection "(k)(1)(C)".

(B) An election under this paragraph is effective —

(i) in the case of an interest which vested after January 1, 1990, and on or before October 24, 1992, if the election is made before the date that is 1 year after October 24, 1992;

(ii) in the case of an interest which vests within 1 year after October 24, 1992, if the election is made before the date that is 2 years after October 24, 1992; and

(iii) in any case other than those described in clause (i) or (ii), if the election is made prior to the interest becoming a vested present interest.

(C) Notwithstanding the consent requirement referenced in section 352 of this title, the Secretary shall issue a noncompetitive lease under subsection (c)(1) of this section to a holder who makes an election under subparagraph (A) and who is qualified to hold a lease under this chapter. Such lease shall be subject to all terms and conditions under this chapter that are applicable to leases issued under subsection (c)(1) of this section.

(D) A lease issued pursuant to this paragraph shall continue so long as oil or gas continues to be produced in paying quantities.

(E) This paragraph shall apply only to those lands under the administration of the Secretary of Agriculture where the United States acquired an interest in such lands pursuant to the Act of March 1, 1911 (36 Stat. 961 and following).

(c) Lands subject to leasing under subsection (b); first qualified applicant

(1) If the lands to be leased are not leased under subsection (b)(1) of this section or are not subject to competitive leasing under subsection (b)(2) of this section, the person first making application for the lease who is qualified to hold a lease under this chapter shall be entitled to a lease of such lands without competitive bidding, upon payment of a non-refundable application fee of at least $75. A lease under this subsection shall be conditioned upon the payment of a royalty at a rate of 12.5 percent in amount or value of the production removed or sold from the lease. Leases shall be issued within 60 days of the date on which the Secretary identifies the first responsible qualified applicant.

(2)(A) Lands (i) which were posted for sale under subsection (b)(1) of this section but for which no bids were received or for which the

highest bid was less than the national minimum acceptable bid and (ii) for which, at the end of the period referred to in subsection (b)(1) of this section no lease has been issued and no lease application is pending under paragraph (1) of this subsection, shall again be available for leasing only in accordance with subsection (b)(1) of this section.

(B) The land in any lease which is issued under paragraph (1) of this subsection or under subsection (b)(1) of this section which lease terminates, expires, is cancelled or is relinquished shall again be available for leasing only in accordance with subsection (b)(1) of this section.

30 U.S.C. § 228:

§ 228. Prospecting permits and leases to persons of lands not withdrawn; terms and conditions of; fraud of claimants

Any person who on October 1, 1919, was a bona fide occupant or claimant of oil or gas lands under a claim initiated while such lands were not withdrawn from oil or gas location and entry, and who had previously performed all acts under then existing laws necessary to valid locations thereof except to make discovery, and upon which discovery had not been made prior to February 25, 1920, and who has performed work or expended on or for the benefit of such locations an amount equal in the aggregate of $250 for each location if application therefor shall be made within six months from February 25, 1920,

shall be entitled to prospecting permits thereon upon the same terms and conditions, and limitations as to acreage, as other permits provided for in this chapter, or where any such person has made such discovery, prior to said February 25, 1920, he shall be entitled to a lease thereon under such terms as the Secretary of the Interior may prescribe unless otherwise provided for in section 227[1] of this title: *Provided*, That where such prospecting permit is granted upon land within any known geologic structure of a producing oil or gas field, the royalty to be fixed in any lease thereafter granted thereon or any portion thereof shall be not less than 12 1/2 per-centum of all the oil or gas produced except oil or gas used for production purposes on the claim, or unavoidably lost: *Provided, however*, That the provisions of this section shall not apply to lands reserved for the use of the Navy. No claimant for a permit or lease who has been guilty of any fraud or who had knowledge or reasonable grounds to know of any fraud, or who has not acted honestly and in good faith shall be entitled to any of the benefits of this section.

All permits or leases hereunder shall inure to the benefit of the claimant and all persons claiming through or under him by lease, contract, or otherwise, as their interests may appear.

(Feb. 25, 1920, ch. 85, § 19, 41 Stat. 445.)

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1. See References in Text note below.

Appendix F

30 U.S.C. § 229:

§ 229. Preference right to permits or leases of claimants of lands bona fide entered as agricultural land; terms and conditions

In the case of lands bona fide entered as agricultural, and not withdrawn or classified as mineral at the time of entry, but not including lands claimed under any railroad grant, the entryman or patentee, or assigns, where assignment was made prior to January 1, 1918, if the entry has been patented with the mineral right reserved, shall be entitled to a preference right to a permit and to a lease, as herein provided, in case of discovery; and within an area not greater than a township such entryman and patentees, or assigns holding restricted patents may combine their holdings, not to exceed two thousand five hundred and sixty acres for the purpose of making joint application. Leases executed under this section and embracing only lands so entered shall provide for the payment of a royalty of not less than 12 1/2 per centum as to such areas within the permit as may not be included within the discovery lease to which the permittee is entitled under section 223 of this title.

(Feb. 25, 1920, ch. 85, § 20, 41 Stat. 445.)

Appendix F

30 U.S.C. § 301:

§ 301. Authorization for lease of oil and gas deposits; by and to whom leased

Whenever the Secretary of the Interior shall deem it to be consistent with the public interest he is authorized to lease deposits of oil and gas in or under lands embraced in railroad or other rights of way acquired under any law of the United States, whether the same be a base fee or mere easement: *Provided*, That, except as hereinafter authorized, no lease shall be executed hereunder except to the municipality, corporation, firm, association, or individual by whom such right of way was acquired, or to the lawful successor, assignee, or transferee of such municipality, corporation, firm, association, or individual.

(May 21, 1930, ch. 307, § 1, 46 Stat. 373.)

Appendix F

30 U.S.C. § 305:

§ 305. Royalties under lease

The royalty to be paid to the United States under any lease to be issued, or agreement made pursuant to this chapter, shall be determined by the Secretary of the Interior, in no case to be less than 12 1/2 per centum in amount or value of the production, nor for more than twenty years: *Provided*, That when the oil or gas is produced from land adjacent to the right of way the amount or value of the royalty to be paid to the United States shall be within the discretion of the Secretary of the Interior: *Provided further*, That when the daily average production of any oil well does not exceed ten barrels per day said Secretary may, in his discretion, reduce the royalty on subsequent production.

(May 21, 1930, ch. 307, § 5, 46 Stat. 374.)

Appendix F

MINERAL LEASING ACT FOR ACQUIRED LANDS

30 U.S.C. § 352:

§ 352. Deposits subject to lease; consent of department heads; lands excluded

Except where lands have been acquired by the United States for the development of the mineral deposits, by foreclosure or otherwise for resale, or reported as surplus pursuant to the provisions of the Surplus Property Act of October 3, 1944 (50 U.S.C., sec. 1611 and the following), all deposits of coal, phosphate, oil, oil shale, gilsonite (including all vein-type solid hydrocarbons), gas, sodium, potassium, and sulfur which are owned or may hereafter be acquired by the United States and which are within the lands acquired by the United States (exclusive of such deposits in such acquired lands as are (a) situated within incorporated cities, towns and villages, national parks or monuments, or (b) tidelands or submerged lands) may be leased by the Secretary under the same conditions as contained in the leasing provisions of the mineral leasing laws, subject to the provisions hereof. Coal or lignite under acquired lands set apart for military or naval purposes may be leased by the Secretary, with the concurrence of the Secretary of Defense, to a governmental entity (including any corporation primarily acting as an agency or instrumentality of a State) which produces electrical energy for sale to the public if such governmental entity is located in the State in which

such lands are located. The provisions of subchapter VIII of chapter 3A of this title shall apply to deposits of sulfur covered by this chapter wherever situated. No mineral deposit covered by this section shall be leased except with the consent of the head of the executive department, independent establishment, or instrumentality having jurisdiction over the lands containing such deposit, or holding a mortgage or deed of trust secured by such lands which is unsatisfied of record, and subject to such conditions as that official may prescribe to insure the adequate utilization of the lands for the primary purposes for which they have been acquired or are being administered: *Provided*, That nothing in this chapter is intended, or shall be construed, to apply to or in any manner affect any mineral rights, exploration permits, leases or conveyances nor minerals that are or may be in any tidelands; or submerged lands; or in lands underlying the three mile zone or belt involved in the case of the United States of America against the State of California now pending on application for rehearing in the Supreme Court of the United States; or in lands underlying such three mile zone or belt, or the continental shelf, adjacent or littoral to any part of the land within the jurisdiction of the United States of America.

(Aug. 7, 1947, ch. 513, § 3, 61 Stat. 914; Pub. L. 94-377, § 12, Aug. 4, 1976, 90 Stat. 1090; Pub. L. 97-78, § 1(9)(b), Nov. 16, 1981, 95 Stat. 1072.)

Appendix F

INDIAN LEASING STATUTES

25 U.S.C. § 396:

§ 396. Leases of allotted lands for mining purposes

All lands allotted to Indians in severalty, except allotments made to members of the Five Civilized Tribes and Osage Indians in Oklahoma, may by said allottee be leased for mining purposes for any term of years as may be deemed advisable by the Secretary of the Interior; and the Secretary of the Interior is authorized to perform any and all acts and make such rules and regulations as may be necessary for the purpose of carrying the provisions of this section into full force and effect: *Provided*, That if the said allottee is deceased and the heirs to or devisees of any interest in the allotment have not been determined, or, if determined, some or all of them cannot be located, the Secretary of the Interior may offer for sale leases for mining purposes to the highest responsible qualified bidder, at public auction, or on sealed bids, after notice and advertisement, upon such terms and conditions as the Secretary of the Interior may prescribe. The Secretary of the Interior shall have the right to reject all bids whenever in his judgment the interests of the Indians will be served by so doing, and to readvertise such lease for sale.

(Mar. 3, 1909, ch. 263, 35 Stat. 783; Aug. 9, 1955, ch. 615, § 3, 69 Stat. 540.)

Appendix F

25 U.S.C. § 396a:

§ 396a. Leases of unallotted lands for mining purposes; duration of leases

On and after May 11, 1938, unallotted lands within any Indian reservation or lands owned by any tribe, group, or band of Indians under Federal jurisdiction, except those specifically excepted from the provisions of sections 396a to 396g of this title, may, with the approval of the Secretary of the Interior, be leased for mining purposes, by authority of the tribal council or other authorized spokesmen for such Indians, for terms not to exceed ten years and as long thereafter as minerals are produced in paying quantities.

(May 11, 1938, ch. 198, § 1, 52 Stat. 347.)

Appendix F

25 U.S.C. § 396d:

§ 396d. Rules and regulations governing operations; limitations on oil or gas leases

All operations under any oil, gas, or other mineral lease issued pursuant to the terms of sections 396a to 396g of this title or any other Act affecting restricted Indian lands shall be subject to the rules and regulations promulgated by the Secretary of the Interior. In the discretion of the said Secretary, any lease for oil or gas issued under the provisions of sections 396a to 396g of this title shall be made subject to the terms of any reasonable cooperative unit or other plan approved or prescribed by said Secretary prior or subsequent to the issuance of any such lease which involves the development or production of oil or gas from land covered by such lease.

(May 11, 1938, ch. 198, § 4, 52 Stat. 348.)

Appendix F

OUTER CONTINENTAL SHELF LANDS ACT

43 U.S.C. § 1334(a):

§ 1334. Administration of leasing

(a) Rules and regulations; amendment; cooperation with State agencies; subject matter and scope of regulations

The Secretary shall administer the provisions of this subchapter relating to the leasing of the outer Continental Shelf, and shall prescribe such rules and regulations as may be necessary to carry out such provisions. The Secretary may at any time prescribe and amend such rules and regulations as he determines to be necessary and proper in order to provide for the prevention of waste and conservation of the natural resources of the outer Continental Shelf, and the protection of correlative rights therein, and, notwithstanding any other provisions herein, such rules and regulations shall, as of their effective date, apply to all operations conducted under a lease issued or maintained under the provisions of this subchapter. In the enforcement of safety, environmental, and conservation laws and regulations, the Secretary shall cooperate with the relevant departments and agencies of the Federal Government and of the affected States. In the formulation and promulgation of regulations, the Secretary shall request and give due consideration to the views of the Attorney General with respect

to matters which may affect competition. In considering any regulations and in preparing any such views, the Attorney General shall consult with the Federal Trade Commission. The regulations prescribed by the Secretary under this subsection shall include, but not be limited to, provisions —

(1) for the suspension or temporary prohibition of any operation or activity, including production, pursuant to any lease or permit (A) at the request of a lessee, in the national interest, to facilitate proper development of a lease or to allow for the construction or negotiation for use of transportation facilities, or (B) if there is a threat of serious, irreparable, or immediate harm or damage to life (including fish and other aquatic life), to property, to any mineral deposits (in areas leased or not leased), or to the marine, coastal, or human environment, and for the extension of any permit or lease affected by suspension or prohibition under clause (A) or (B) by a period equivalent to the period of such suspension or prohibition, except that no permit or lease shall be so extended when such suspension or prohibition is the result of gross negligence or willful violation of such lease or permit, or of regulations issued with respect to such lease or permit;

(2) with respect to cancellation of any lease or permit —

(A) that such cancellation may occur at any time, if the Secretary determines, after a hearing, that —

(i) continued activity pursuant to such lease or permit would probably cause serious harm or damage to life (including fish and other aquatic life), to property, to any mineral (in areas leased or not leased), to the national security or defense, or to the marine, coastal, or human environment;

(ii) the threat of harm or damage will not disappear or decrease to an acceptable extent within a reasonable period of time; and

(iii) the advantages of cancellation outweigh the advantages of continuing such lease or permit in force;

(B) that such cancellation shall not occur unless and until operations under such lease or permit shall have been under suspension, or temporary prohibition, by the Secretary, with due extension of any lease or permit term continuously for a period of five years, or for a lesser period upon request of the lessee;

(C) that such cancellation shall entitle the lessee to receive such compensation as he shows to the Secretary as being equal to the lesser of (i) the fair value of the canceled rights as of the date of cancellation, taking account of both anticipated revenues from the lease and anticipated costs, including costs of compliance with all applicable regulations and operating orders, liability for cleanup costs or damages, or both, in the case of an oil spill, and all other costs reasonably anticipated on the lease, or (ii) the excess, if any, over the lessee's revenues, from the lease (plus interest thereon from the date of receipt to date of reimbursement) of all consideration paid for the lease and all direct expenditures made by the lessee after the date of issuance of such lease and in connection with exploration or development, or both, pursuant to the lease (plus interest on such consideration and such expenditures from date of payment to date of reimbursement), except that (I) with respect to leases issued before September 18, 1978, such compensation shall be equal to the amount specified in clause (i) of this subparagraph; and (II) in the case of joint leases which are canceled due to the failure of one or more partners to exercise due diligence, the innocent parties shall have the right to seek damages for such loss from the responsible party or parties and the right to acquire the interests of the negligent party or parties and be issued the lease in question;

(3) for the assignment or relinquishment of a lease;

(4) for unitization, pooling, and drilling agreements;

(5) for the subsurface storage of oil and gas other than by the Federal Government;

(6) for drilling or easements necessary for exploration, development, and production;

(7) for the prompt and efficient exploration and development of a lease area; and

(8) for compliance with the national ambient air quality standards pursuant to the Clean Air Act (42 U.S.C. 7401 et seq.), to the extent that activities authorized under this subchapter significantly affect the air quality of any State.

Appendix F

43 U.S.C. § 1335(a):

§ 1335. Validation and maintenance of prior leases

(a) Requirements for validation

The provisions of this section shall apply to any mineral lease covering submerged lands of the outer Continental Shelf issued by any State (including any extension, renewal, or replacement thereof heretofore granted pursuant to such lease or under the laws of such State) if —

(1) such lease, or a true copy thereof, is filed with the Secretary by the lessee or his duly authorized agent within ninety days from August 7, 1953, or within such further period or periods as provided in section 1336 of this title or as may be fixed from time to time by the Secretary;

(2) such lease was issued prior to December 21, 1948, and would have been on June 5, 1950, in force and effect in accordance with its terms and provisions and the law of the State issuing it had the State had the authority to issue such lease;

(3) there is filed with the Secretary, within the period or periods specified in paragraph (1) of this subsection, (A) a certificate issued by the State official or agency

having jurisdiction over such lease stating that it would have been in force and effect as required by the provisions of paragraph (2) of this subsection, or (B) in the absence of such certificate, evidence in the form of affidavits, receipts, canceled checks, or other documents that may be required by the Secretary, sufficient to prove that such lease would have been so in force and effect;

(4) except as otherwise provided in section 1336 of this title hereof, all rents, royalties, and other sums payable under such lease between June 5, 1950, and August 7, 1953, which have not been paid in accordance with the provisions thereof, or to the Secretary or to the Secretary of the Navy, are paid to the Secretary within the period or periods specified in paragraph (1) of this subsection, and all rents, royalties, and other sums payable under such lease after August 7, 1953, are paid to the Secretary, who shall deposit such payments in the Treasury in accordance with section 1338 of this title;

(5) the holder of such lease certifies that such lease shall continue to be subject to the overriding royalty obligations existing on August 7, 1953;

(6) such lease was not obtained by fraud or misrepresentation;

(7) such lease, if issued on or after June 23, 1947, was issued upon the basis of competitive bidding;

(8) such lease provides for a royalty to the lessor on oil and gas of not less than 12 1/2 per centum and on sulphur of not less than 5 per centum in amount or value of the production saved, removed, or sold from the lease, or, in any case in which the lease provides for a lesser royalty, the holder thereof consents in writing, filed with the Secretary, to the increase of the royalty to the minimum herein specified;

(9) the holder thereof pays to the Secretary within the period or periods specified in paragraph (1) of this subsection an amount equivalent to any severance, gross production, or occupation taxes imposed by the State issuing the lease on the production from the lease, less the State's royalty interest in such production, between June 5, 1950, and August 7, 1953 and not heretofore paid to the State, and thereafter pays to the Secretary as an additional royalty on the production from the lease, less the United States' royalty interest in such production, a sum of money equal to the amount of the severance, gross production, or occupation taxes which would have been payable on such production to the State issuing the lease under its laws as they existed on August 7, 1953;

(10) such lease will terminate within a period of not more than five years from August 7, 1953 in the absence of production or operations for drilling, or, in any case in which the lease provides for a longer period, the holder thereof consents in writing, filed with the Secretary, to the reduction of such period so that it will not exceed the maximum period herein specified; and

(11) the holder of such lease furnishes such surety bond, if any, as the Secretary may require and complies with such other reasonable requirements as the Secretary may deem necessary to protect the interests of the United States.

Appendix F

43 U.S.C. § 1337(a)(1):

§ 1337. Grant of leases by Secretary

(a) Oil and gas leases; award to highest responsible qualified bidder; method of bidding; royalty relief; Congressional consideration of bidding system; notice

(1) The Secretary is authorized to grant to the highest responsible qualified bidder or bidders by competitive bidding, under regulations promulgated in advance, any oil and gas lease on submerged lands of the outer Continental Shelf which are not covered by leases meeting the requirements of subsection (a) of section 1335 of this title. Such regulations may provide for the deposit of cash bids in an interest-bearing account until the Secretary announces his decision on whether to accept the bids, with the interest earned thereon to be paid to the Treasury as to bids that are accepted and to the unsuccessful bidders as to bids that are rejected. The bidding shall be by sealed bid and, at the discretion of the Secretary, on the basis of —

(A) cash bonus bid with a royalty at not less than 12 1/2 per centum fixed by the Secretary in amount or value of the production saved, removed, or sold;

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(B) variable royalty bid based on a per centum in amount or value of the production saved, removed, or sold, with either a fixed work commitment based on dollar amount for exploration or a fixed cash bonus as determined by the Secretary, or both;

(C) cash bonus bid, or work commitment bid based on a dollar amount for exploration with a fixed cash bonus, and a diminishing or sliding royalty based on such formulae as the Secretary shall determine as equitable to encourage continued production from the lease area as resources diminish, but not less than 12 1/2 per centum at the beginning of the lease period in amount or value of the production saved, removed, or sold;

(D) cash bonus bid with a fixed share of the net profits of no less than 30 per centum to be derived from the production of oil and gas from the lease area;

(E) fixed cash bonus with the net profit share reserved as the bid variable;

(F) cash bonus bid with a royalty at no less than 12 1/2 per centum fixed by the Secretary in amount or value of the production saved, removed, or sold and a fixed per centum share of net profits of no less than 30 per centum to be derived from the production of oil and gas from the lease area;

(G) work commitment bid based on a dollar amount for exploration with a fixed cash bonus and a fixed royalty in amount or value of the production saved, removed, or sold;

(H) cash bonus bid with royalty at no less than 12 and 1/2 per centum fixed by the Secretary in amount or value of production saved, removed, or sold, and with suspension of royalties for a period, volume, or value of production determined by the Secretary, which suspensions may vary based on the price of production from the lease; or

(I) subject to the requirements of paragraph (4) of this subsection, any modification of bidding systems authorized in subparagraphs (A) through (G), or any other systems of bid variables, terms, and conditions which the Secretary determines to be useful to accomplish the purposes and policies of this subchapter, except that no such bidding system or modification shall have more than one bid variable.

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43 U.S.C. § 1337(b)(3):

§ 1337. Grant of leases by Secretary

(b) Terms and provisions of oil and gas leases

An oil and gas lease issued pursuant to this section shall —

* * *

(3) require the payment of amount or value as determined by one of the bidding systems set forth in subsection (a) of this section;

* * * *

APPENDIX G — RELEVANT REGULATIONS

30 C.F.R. § 206.152(i) (1999):

§ 206.152 Valuation standards — unprocessed gas.

> (i) The lessee must place gas in marketable condition and market the gas for the mutual benefit of the lessee and the lessor at no cost to the Federal Government. Where the value established under this section is determined by a lessee's gross proceeds, that value will be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the lessee to place the gas in marketable condition or to market the gas.

30 C.F.R. § 206.153(i) (2000):

§ 206.153 Valuation standards — processed gas.

> (i) The lessee must place residue gas and gas plant products in marketable condition and market the residue gas and gas plant products for the mutual benefit of the lessee and the lessor at no cost to the Federal Government. Where the value established under this section is determined by a lessee's gross proceeds, that value will be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the

lessee to place the residue gas or gas plant products in marketable condition or to market the residue gas and gas plant products.

30 C.F.R. § 206.157(f) (1999):

§ 206.157 Determination of transportation allowances.

(f) *Allowable costs in determining transportation allowances.* Lessees may include, but are not limited to, the following costs in determining the arm's-length transportation allowance under paragraph (a) of this section or the non-arm's-length transportation allowance under paragraph (b) of this section:

(1) *Firm demand charges paid to pipelines.* You must limit the allowable costs for the firm demand charges to the applicable rate per MMBtu multiplied by the actual volumes transported. You may not include any losses incurred for previously purchased but unused firm capacity. You also may not include any gains associated with releasing firm capacity. If you receive a payment or credit from the pipeline for penalty refunds, rate case refunds, or other reasons, you must reduce the firm demand charge claimed on the Form MMS-2014. You must modify the Form MMS-2014 by the amount received or credited for the affected reporting period;

(2) *Gas supply realignment (GSR) costs.* The GSR costs result from a pipeline reforming or terminating supply contracts with producers to implement the restructuring requirements of FERC Orders in 18 CFR part 284;

(3) *Commodity charges.* The commodity charge allows the pipeline to recover the costs of providing service;

(4) *Wheeling costs.* Hub operators charge a wheeling cost for transporting gas from one pipeline to either the same or another pipeline through a market center or hub. A hub is a connected manifold of pipelines through which a series of incoming pipelines are interconnected to a series of outgoing pipelines;

(5) *Gas Research Institute (GRI) fees.* The GRI conducts research, development, and commercialization programs on natural gas related topics for the benefit of the U.S. gas industry and gas customers. GRI fees are allowable provided such fees are mandatory in FERC-approved tariffs;

(6) *Annual Charge Adjustment (ACA) fees.* FERC charges these fees to pipelines to pay for its operating expenses;

(7) *Payments (either volumetric or in value) for actual or theoretical losses.* This paragraph does not apply to non-arm's-length transportation arrangements unless the transportation allowance is based on a FERC or State regulatory-approved tariff;

(8) *Temporary storage services.* This includes short duration storage services offered by market centers or hubs (commonly referred to as "parking" or "banking"), or other temporary storage services provided by pipeline transporters, whether actual or provided as a matter of accounting. Temporary storage is limited to 30 days or less; and

(9) *Supplemental costs for compression, dehydration, and treatment of gas.* MMS allows these costs only if such services are required for transportation and exceed the services necessary to place production into marketable condition required under §§ 206.152(i) and 206.153(i) of this part.

(g) *Nonallowable costs in determining transportation allowances.* Lessees may not include the following costs in determining the arm's-length transportation allowance under paragraph (a) of this section or the non-arm's-length transportation allowance under paragraph (b) of this section:

(1) *Fees or costs incurred for storage.* This includes storing production in a storage

facility, whether on or off the lease, for more than 30 days;

(2) *Aggregator/marketer fees.* This includes fees you pay to another person (including your affiliates) to market your gas, including purchasing and reselling the gas, or finding or maintaining a market for the gas production;

(3) *Penalties you incur as shipper.* These penalties include, but are not limited to:

(i) *Over-delivery cash-out penalties.* This includes the difference between the price the pipeline pays you for over-delivered volumes outside the tolerances and the price you receive for over-delivered volumes within the tolerances;

(ii) *Scheduling penalties.* This includes penalties you incur for differences between daily volumes delivered into the pipeline and volumes scheduled or nominated at a receipt or delivery point;

(iii) *Imbalance penalties.* This includes penalties you incur (generally on a monthly basis) for differences between volumes delivered into the pipeline and volumes scheduled or nominated at a receipt or delivery point; and

(iv) *Operational penalties.* This includes fees you incur for violation of the pipeline's curtailment or operational orders issued to protect the operational integrity of the pipeline;

(4) *Intra-hub transfer fees.* These are fees you pay to hub operators for administrative services (e.g., title transfer tracking) necessary to account for the sale of gas within a hub; and

(5) *Other nonallowable costs.* Any cost you incur for services you are required to provide at no cost to the lessor.

(h) *Other transportation cost determinations.* Use this section when calculating transportation costs to establish value using a netback procedure or any other procedure that requires deduction of transportation costs.

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30 C.F.R. § 206.172(i) (1999):

§ 206.172 Valuation standards — unprocessed gas.

(i) The lessee must place gas in marketable condition and market the gas for the mutual benefit of the lessee and the lessor at no cost to the Indian lessor. Where the value established under this section is determined by a lessee's gross proceeds, that value will be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the lessee to place the gas in marketable condition or to market the gas.

30 C.F.R. § 206.173(i) (1999):

§ 206.173 Valuation standards — processed gas.

(i) The lessee must place residue gas and gas plant products in marketable condition and market the residue gas and gas plant products for the mutual benefit of the lessee and the lessor at no cost to the Indian lessor. Where the value established under this section is determined by a lessee's gross proceeds, that value will be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the lessee to place the residue gas or gas plant products in marketable condition or to market the residue gas and gas plant products.

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30 C.F.R. §§ 206.177(f), (g) & (h) (1999):

§ 206.177 Determination of transportation allowances.

(f) *Allowable costs in determining transportation allowances.* Lessees may include, but are not limited to, the following costs in determining the arm's-length transportation allowance under paragraph (a) of this section or the non-arm's-length transportation allowance under paragraph (b) of this section:

(1) *Firm demand charges paid to pipelines.* You must limit the allowable costs for the firm demand charges to the applicable rate per MMBtu multiplied by the actual volumes transported. You may not include any losses incurred for previously purchased but unused firm capacity. You also may not include any gains associated with releasing firm capacity. If you receive a payment or credit from the pipeline for penalty refunds, rate case refunds, or other reasons, you must reduce the firm demand charge claimed on the Form MMS-2014. You must modify the Form MMS-2014 by the amount received or credited for the affected reporting period;

(2) *Gas supply realignment (GSR) costs.* The GSR costs result from a pipeline reforming or terminating supply contracts

with producers to implement the restructuring requirements of FERC Orders in 18 CFR part 284;

(3) *Commodity charges.* The commodity charge allows the pipeline to recover the costs of providing service;

(4) *Wheeling costs.* Hub operators charge a wheeling cost for transporting gas from one pipeline to either the same or another pipeline through a market center or hub. A hub is a connected manifold of pipelines through which a series of incoming pipelines are interconnected to a series of outgoing pipelines;

(5) *Gas Research Institute (GRI) fees.* The GRI conducts research, development, and commercialization programs on natural gas related topics for the benefit of the U.S. gas industry and gas customers. GRI fees are allowable provided such fees are mandatory in FERC-approved tariffs;

(6) *Annual Charge Adjustment (ACA) fees.* FERC charges these fees to pipelines to pay for its operating expenses;

(7) *Payments (either volumetric or in value) for actual or theoretical losses.* This paragraph does not apply to non-arm's-

length transportation arrangements unless the transportation allowance is based on a FERC or State regulatory-approved tariff;

(8) *Temporary storage services.* This includes short duration storage services offered by market centers or hubs (commonly referred to as "parking" or "banking"), or other temporary storage services provided by pipeline transporters, whether actual or provided as a matter of accounting. Temporary storage is limited to 30 days or less; and

(9) *Supplemental costs for compression, dehydration, and treatment of gas.* MMS allows these costs only if such services are required for transportation and exceed the services necessary to place production into marketable condition required under §§ 206.172(i) and 206.173(i) of this part.

(g) *Nonallowable costs in determining transportation allowances.* Lessees may not include the following costs in determining the arm's-length transportation allowance under paragraph (a) of this section or the non-arm's-length transportation allowance under paragraph (b) of this section:

(1) *Fees or costs incurred for storage.* This includes storing production in a storage facility, whether on or off the lease, for more than 30 days;

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(2) *Aggregator/marketer fees.* This includes fees you pay to another person (including your affiliates) to market your gas, including purchasing and reselling the gas, or finding or maintaining a market for the gas production;

(3) *Penalties you incur as shipper.* These penalties include, but are not limited to:

(i) *Over-delivery cash-out penalties.* This includes the difference between the price the pipeline pays you for over-delivered volumes outside the tolerances and the price you receive for over-delivered volumes within the tolerances;

(ii) *Scheduling penalties.* This includes penalties you incur for differences between daily volumes delivered into the pipeline and volumes scheduled or nominated at a receipt or delivery point;

(iii) *Imbalance penalties.* This includes penalties you incur (generally on a monthly basis) for differences between volumes delivered into the pipeline and volumes scheduled or nominated at a receipt or delivery point; and

(iv) *Operational penalties.* This includes fees you incur for violation of the pipeline's curtailment or operational orders issued to protect the operational integrity of the pipeline;

(4) *Intra-hub transfer fees.* These are fees you pay to hub operators for administrative services (e.g., title transfer tracking) necessary to account for the sale of gas within a hub; and

(5) *Other nonallowable costs.* Any cost you incur for services you are required to provide at no cost to the lessor.

(h) *Other transportation cost determinations.* Use this section when calculating transportation costs to establish value using a netback procedure or any other procedure that requires deduction of transportation costs.

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30 C.F.R. § 206.152 (1994):

§ 206.152 Valuation standards — unprocessed gas.

(a)(1) This section applies to the valuation of all gas that is not processed and all gas that is processed but is sold or otherwise disposed of by the lessee pursuant to an arm's-length contract prior to processing (including all gas where the lessee's arm's-length contract for the sale of that gas prior to processing provides for the value to be determined on the basis of a percentage of the purchaser's proceeds resulting from processing the gas). This section also applies to processed gas that must be valued prior to processing in accordance with § 206.155 of this part. Where the lessee's contract includes a reservation of the right to process the gas and the lessee exercises that right, § 206.153 of this part shall apply instead of this section.

(2) The value of production, for royalty purposes, of gas subject to this subpart shall be the value of gas determined under this section less applicable allowances determined pursuant to this subpart.

(3)(i) For any Indian leases which provide that the Secretary may consider the highest price paid or offered for a major portion of production (major portion) in determining value of production for royalty purposes, if data are available to

compute a major portion MMS will, where practicable, compare the value determined in accordance with this section with the major portion. The value to be used in determining the value of production for royalty purposes shall be the higher of those two values.

(ii) For purposes of this paragraph, major portion means the highest price paid or offered at the time of production for the major portion of gas production from the same field. The major portion will be calculated using like-quality gas sold under arm's-length contracts from the same field (or, if necessary to obtain a reasonable sample, from the same area) for each month. All such sales will be arrayed from highest price to lowest price (at the bottom). The major portion is that price at which 50 percent (by volume) plus 1 mcf of the gas (starting from the bottom) is sold.

(b)(1)(i) The value of gas which is sold pursuant to arm's-length contract shall be the gross proceeds accruing to the lessee, except as provided in paragraphs (b)(1) (ii) and (iii) of this section. The lessee shall have the burden of demonstrating that its contract is arm's-length. The value which the lessee reports, for royalty purposes, is subject to monitoring, review, and audit. For purposes of this section, gas which is sold or otherwise transferred to the lessee's marketing affiliate and then sold by the marketing affiliate pursuant to an arm's-length contract shall be valued in

accordance with this paragraph based upon the sale by the marketing affiliate. Also, where the lessee's arm's-length contract for the sale of gas prior to processing provides for the value to be determined based upon a percentage of the purchaser's proceeds resulting from processing the gas, the value of production, for royalty purposes, shall never be less than a value equivalent to 100 percent of the value of the residue gas attributable to the processing of the lessee's gas.

(ii) In conducting reviews and audits, MMS will examine whether the contract reflects the total consideration actually transferred either directly or indirectly from the buyer to the seller for the gas. If the contract does not reflect the total consideration, then the MMS may require that the gas sold pursuant to that contract be valued in accordance with paragraph (c) of this section. Value may not be less than the gross proceeds accruing to the lessee, including the additional consideration.

(iii) If the MMS determines that the gross proceeds accruing to the lessee pursuant to an arm's-length contract do not reflect the reasonable value of the production because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS shall

require that the gas production be valued pursuant to paragraph(c)(2) or (c)(3) of this section, and in accordance with the notification requirements of paragraph (e) of this section. When MMS determines that the value may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's value.

(2) Notwithstanding the provisions of paragraph (b)(1) of this section, the value of gas sold pursuant to a warranty contract shall be determined by MMS, and due consideration will be given to all valuation criteria specified in this section. The lessee must request a value determination in accordance with paragraph (g) of this section for gas sold pursuant to a warranty contract; provided, however, that any value determination for a warranty contract in effect on the effective date of these regulations shall remain in effect until modified by MMS.

(3) MMS may require a lessee to certify that its arm's-length contract provisions include all of the consideration to be paid by the buyer, either directly or indirectly, for the gas.

(c) The value of gas subject to this section which is not sold pursuant to an arm's-length contract shall be the reasonable value determined in accordance with the first applicable of the following methods:

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(1) The gross proceeds accruing to the lessee pursuant to a sale under its non-arm's-length contract (or other disposition other than by an arm's-length contract), provided that those gross proceeds are equivalent to the gross proceeds derived from, or paid under, comparable arm's-length contracts for purchases, sales, or other dispositions of like-quality gas in the same field (or, if necessary to obtain a reasonable sample, from the same area). In evaluating the comparability of arm's-length contracts for the purposes of these regulations, the following factors shall be considered: price, time of execution, duration, market or markets served, terms, quality of gas, volume, and such other factors as may be appropriate to reflect the value of the gas;

(2) A value determined by consideration of other information relevant in valuing like-quality gas, including gross proceeds under arm's-length contracts for like-quality gas in the same field or nearby fields or areas, posted prices for gas, prices received in arm's-length spot sales of gas, other reliable public sources of price or market information, and other information as to the particular lease operation or the saleability of the gas; or

(3) A net-back method or any other reasonable method to determine value.

(d)(1) Notwithstanding any other provisions of this section, except paragraph (h) of this section, if the maximum price permitted by Federal law at which gas may be sold is less than the value determined pursuant to this section, then MMS shall accept such maximum price as the value. For purposes of this section, price limitations set by any State or local government shall not be considered as a maximum price permitted by Federal law.

(2) The limitation prescribed in paragraph (d)(1) of this section shall not apply to gas sold pursuant to a warranty contract and valued pursuant to paragraph (b)(2) of this section.

(e)(1) Where the value is determined pursuant to paragraph (c) of this section, the lessee shall retain all data relevant to the determination of royalty value. Such data shall be subject to review and audit, and MMS will direct a lessee to use a different value if it determines that the reported value is inconsistent with the requirements of these regulations.

(2) Any Federal or Indian lessee will make available upon request to the authorized MMS or State, or Indian representatives, to the Office of the Inspector General of the Department of the Interior, or other person authorized to receive such information, arm's-length sales and volume data for like-quality production sold, purchased or otherwise obtained by the lessee from the field or area or from nearby fields or areas.

(3) A lessee shall notify MMS if it has determined value pursuant to paragraph (c)(2) or (c)(3) of this section. The notification shall be by letter to the MMS Associate Director for Royalty Management or his/her designee. The letter shall identify the valuation method to be used and contain a brief description of the procedure to be followed. The notification required by this paragraph is a one-time notification due no later than the end of the month following the month the lessee first reports royalties on a Form MMS-2014 using a valuation method authorized by paragraph (c)(2) or (c)(3) of this section, and each time there is a change in a method under paragraph (c)(2) or (c)(3) of this section.

(f) If MMS determines that a lessee has not properly determined value, the lessee shall pay the difference, if any, between royalty payments made based upon the value it has used and the royalty payments that are due based upon the value established by MMS. The lessee shall also pay interest on that difference computed pursuant to 30 CFR 218.54. If the lessee is entitled to a credit, MMS will provide instructions for the taking of that credit.

(g) The lessee may request a value determination from MMS. In that event, the lessee shall propose to MMS a value determination method, and may use that method in determining value for royalty purposes until MMS issues its

decision. The lessee shall submit all available data relevant to its proposal. The MMS shall expeditiously determine the value based upon the lessee's proposal and any additional information MMS deems necessary. In making a value determination MMS may use any of the valuation criteria authorized by this subpart. That determination shall remain effective for the period stated therein. After MMS issues its determination, the lessee shall make the adjustments in accordance with paragraph (f) of this section.

(h) Notwithstanding any other provision of this section, under no circumstances shall the value of production for royalty purposes be less than the gross proceeds accruing to the lessee for lease production, less applicable allowances pursuant to this subpart.

(i) The lessee is required to place gas in marketable condition at no cost to the Federal Government or Indian lessor unless otherwise provided in the lease agreement. Where the value established pursuant to this section is determined by a lessee's gross proceeds, that value shall be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the lessee to place the gas in marketable condition.

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(j) Value shall be based on the highest price a prudent lessee can receive through legally enforceable claims under its contract. If there is no contract revision or amendment, and the lessee fails to take proper or timely action to receive prices or benefits to which it is entitled, it must pay royalty at a value based upon that obtainable price or benefit. Contract revisions or amendments shall be in writing and signed by all parties to an arm's-length contract. If the lessee makes timely application for a price increase or benefit allowed under its contract but the purchaser refuses, and the lessee takes reasonable measures, which are documented, to force purchaser compliance, the lessee will owe no additional royalties unless or until monies or consideration resulting from the price increase or additional benefits are received. This paragraph shall not be construed to permit a lessee to avoid its royalty payment obligation in situations where a purchaser fails to pay, in whole or in part or timely, for a quantity of gas.

(k) Notwithstanding any provision in these regulations to the contrary, no review, reconciliation, monitoring, or other like process that results in a redetermination by the MMS of value under this section shall be considered final or binding as against the Federal Government, its beneficiaries, the Indian Tribes, or allottees until the audit period is formally closed.

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(l) Certain information submitted to MMS to support valuation proposals, including transportation or extraordinary cost allowances, is exempted from disclosure by the Freedom of Information Act, 5 U.S.C. § 552, or other Federal law. Any data specified by law to be privileged, confidential, or otherwise exempt will be maintained in a confidential manner in accordance with applicable law and regulations. All requests for information about determinations made under this subpart are to be submitted in accordance with the Freedom of Information Act regulation of the Department of the Interior, 43 CFR part 2. Nothing in this section is intended to limit or diminish in any manner whatsoever the right of an Indian lessor to obtain any and all information as such lessor may be lawfully entitled from MMS or such lessor's lessee directly under the terms of the lease, 30 U.S.C. 1733, or other applicable law.

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30 C.F.R. § 206.153 (1994):

§ 206.153 Valuation standards — processed gas.

(a)(1) This section applies to the valuation of all gas that is processed by the lessee and any other gas production to which this subpart applies and that is not subject to the valuation provisions of § 206.152 of this part. This section applies where the lessee's contract includes a reservation of the right to process the gas and the lessee exercises that right.

(2) The value of production, for royalty purposes, of gas subject to this section shall be the combined value of the residue gas and all gas plant products determined pursuant to this section, plus the value of any condensate recovered downstream of the point of royalty settlement without resorting to processing determined pursuant to § 206.102 of this part, less applicable transportation allowances and processing allowances determined pursuant to this subpart.

(3)(i) For any Indian leases which provide that the Secretary may consider the highest price paid or offered for a major portion of production (major portion) in determining value for royalty purposes, if data are available to compute a major portion MMS will, where practicable, compare the values determined in accordance with this section for any lease product with the major portion

determined for that lease product. The value to be used in determining the value of production for royalty purposes shall be the higher of those two values.

(ii) For purposes of this paragraph, major portion means the highest price paid or offered at the time of production for the major portion of gas production from the same field, or for residue gas or gas plant products from the same processing plant, as applicable. The major portion will be calculated using like-quality lease products sold under arm's-length contracts from the same field or processing plant (or, if necessary to obtain a reasonable sample, from the same area or nearby processing plants) for each month. All such sales will be arrayed from highest price to lowest price (at the bottom). The major portion is that price at which 50 percent (by volume) plus 1 mcf of the gas (starting from the bottom) is sold, or for gas plant products, 50 percent (by volume) plus 1 unit.

(b)(1)(i) The value of residue gas or any gas plant product sold under an arm's-length contract is the gross proceeds accruing to the lessee, except as provided in paragraphs (b)(1) (ii) and (iii) of this section. The lessee shall have the burden of demonstrating that its contract is arm's-length. The value that the lessee reports for royalty purposes is subject to monitoring, review, and audit. For purposes of this section, residue gas or any gas plant product which is sold or otherwise

transferred to the lessee's marketing affiliate and then sold by the marketing affiliate pursuant to an arm's-length contract shall be valued in accordance with this paragraph based upon the sale by the marketing affiliate.

(ii) In conducting these reviews and audits, MMS will examine whether or not the contract reflects the total consideration actually transferred either directly or indirectly from the buyer to the seller for the residue gas or gas plant product. If the contract does not reflect the total consideration, then the MMS may require that the residue gas or gas plant product sold pursuant to that contract be valued in accordance with paragraph (c) of this section. Value may not be less than the gross proceeds accruing to the lessee, including the additional consideration.

(iii) If the MMS determines that the gross proceeds accruing to the lessee pursuant to an arm's-length contract do not reflect the reasonable value of the residue gas or gas plant product because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS shall require that the residue gas or gas plant product be valued pursuant to paragraphs (c)(2) or (c)(3) of this section, and in accordance with the notification requirements of paragraph (e) of this section.

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When MMS determines that the value may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's value.

(2) Notwithstanding the provisions of paragraph (b)(1) of this section, the value of residue gas sold pursuant to a warranty contract shall be determined by MMS, and due consideration will be given to all valuation criteria specified in this section. The lessee must request a value determination in accordance with paragraph (g) of this section for gas sold pursuant to a warranty contract; provided, however, that any value determination for a warranty contract in effect on the effective date of these regulations shall remain in effect until modified by MMS.

(3) MMS may require a lessee to certify that its arm's-length contract provisions include all of the consideration to be paid by the buyer, either directly or indirectly, for the residue gas or gas plant product.

(c) The value of residue gas or any gas plant product which is not sold pursuant to an arm's-length contract shall be the reasonable value determined in accordance with the first applicable of the following methods:

(1) The gross proceeds accruing to the lessee pursuant to a sale under its non-arm's-length

contract (or other disposition other than by an arm's-length contract), provided that those gross proceeds are equivalent to the gross proceeds derived from, or paid under, comparable arm's-length contracts for purchases, sales, or other dispositions of like quality residue gas or gas plant products from the same processing plant (or, if necessary to obtain a reasonable sample, from nearby plants). In evaluating the comparability of arm's-length contracts for the purposes of these regulations, the following factors shall be considered: price, time of execution, duration, market or markets served, terms, quality of residue gas or gas plant products, volume, and such other factors as may be appropriate to reflect the value of the residue gas or gas plant products;

(2) A value determined by consideration of other information relevant in valuing like-quality residue gas or gas plant products, including gross proceeds under arm's-length contracts for like-quality residue gas or gas plant products from the same gas plant or other nearby processing plants, posted prices for residue gas or gas plant products, prices received in spot sales of residue gas or gas plant products, other reliable public sources of price or market information, and other information as to the particular lease operation or the saleability of such residue gas or gas plant products; or

(3) A net-back method or any other reasonable method to determine value.

(d)(1) Notwithstanding any other provisions of this section, except paragraph (h) of this section, if the maximum price permitted by Federal law at which any residue gas or gas plant products may be sold is less than the value determined pursuant to this section, then MMS shall accept such maximum price as the value. For the purposes of this section, price limitations set by any State or local government shall not be considered as a maximum price permitted by Federal law.

(2) The limitation prescribed by paragraph (d)(1) of this section shall not apply to residue gas sold pursuant to a warranty contract and valued pursuant to paragraph (b)(2) of this section.

(e)(1) Where the value is determined pursuant to paragraph (c) of this section, the lessee shall retain all data relevant to the determination of royalty value. Such data shall be subject to review and audit, and MMS will direct a lessee to use a different value if it determines upon review or audit that the reported value is inconsistent with the requirements of these regulations.

(2) Any Federal or Indian lessee will make available upon request to the authorized MMS or State representatives, to the Office of the Inspector

General of the Department of the Interior, or other persons authorized to receive such information, arm's-length sales and volume data for like-quality residue gas and gas plant products sold, purchased or otherwise obtained by the lessee from the same processing plant or from nearby processing plants.

(3) A lessee shall notify MMS if it has determined any value pursuant to paragraph (c)(2) or (c)(3) of this section. The notification shall be by letter to the MMS Associate Director for Minerals Revenue Management or his/her designee. The letter shall identify the valuation method to be used and contain a brief description of the procedure to be followed. The notification required by this paragraph is a one-time notification due no later than the end of the month following the month the lessee first reports royalties on a Form MMS-2014 using a valuation method authorized by paragraph (c)(2) or (c)(3) of this section, and each time there is a change in a method under paragraph (c)(2) or (c)(3) of this section.

(f) If MMS determines that a lessee has not properly determined value, the lessee shall pay the difference, if any, between royalty payments made based upon the value it has used and the royalty payments that are due based upon the value established by MMS. The lessee shall also pay interest computed on that difference pursuant to

30 CFR 218.54. If the lessee is entitled to a credit, MMS will provide instructions for the taking of that credit.

(g) The lessee may request a value determination from MMS. In that event, the lessee shall propose to MMS a value determination method, and may use that method in determining value for royalty purposes until MMS issues its decision. The lessee shall submit all available data relevant to its proposal. The MMS shall expeditiously determine the value based upon the lessee's proposal and any additional information MMS deems necessary. In making a value determination, MMS may use any of the valuation criteria authorized by this subpart. That determination shall remain effective for the period stated therein. After MMS issues its determination, the lessee shall make the adjustments in accordance with paragraph (f) of this section.

(h) Notwithstanding any other provision of this section, under no circumstances shall the value of production for royalty purposes be less than the gross proceeds accruing to the lessee for residue gas and/or any gas plant products, less applicable transportation allowances and processing allowances determined pursuant to this subpart.

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(i) The lessee is required to place residue gas and gas plant products in marketable condition at no cost to the Federal Government or Indian lessor unless otherwise provided in the lease agreement. Where the value established under this section is determined by a lessee's gross proceeds, that value shall be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the lessee to place the residue gas or gas plant products in marketable condition,

(j) Value shall be based on the highest price a prudent lessee can receive through legally enforceable claims under its contract. Absent contract revision or amendment, if the lessee fails to take proper or timely action to receive prices or benefits to which it is entitled it must pay royalty at a value based upon that obtainable price or benefit. Contract revisions or amendments shall be in writing and signed by all parties to an arm's-length contract. If the lessee makes timely application for a price increase or benefit allowed under its contract but the purchaser refuses, and the lessee takes reasonable measures, which are documented, to force purchaser compliance, the lessee will owe no additional royalties unless or until monies or consideration resulting from the price increase or additional benefits are received. This paragraph shall not be construed to permit a lessee to avoid its royalty payment obligation in

situations where a purchaser fails to pay, in whole or in part, or timely, for a quantity of residue gas or gas plant product.

(k) Notwithstanding any provision in these regulations to the contrary, no review, reconciliation, monitoring, or other like process that results in a redetermination by MMS of value under this section shall be considered final or binding against the Federal Government, or its beneficiaries, the Indian Tribes, or allottees, until the audit period is formally closed.

(l) Certain information submitted to MMS to support valuation proposals, including transportation allowances, processing allowances or extraordinary cost allowances, is exempted from disclosure by the Freedom of Information Act, 5 U.S.C. 552, or other Federal law. Any data specified by law to be privileged, confidential, or otherwise exempt, will be maintained in a confidential manner in accordance with applicable law and regulations. All requests for information about determinations made under this part are to be submitted in accordance with the Freedom of Information Act regulation of the Department of the Interior, 43 CFR part 2. Nothing in this section is intended to limit or diminish in any manner whatsoever the right of an Indian lessor to obtain any and all information as such lessor may be lawfully entitled from the MMS or such lessor's lessee directly under the terms of the lease, 30 U.S.C. 1733, or other applicable law.

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30 C.F.R. § 206.156 (1994):

§ 206.156 Transportation allowances — general.

(a) Where the value of gas has been determined pursuant to § 206.152 or § 206.153 of this subpart at a point (e.g., sales point or point of value determination) off the lease, MMS shall allow a deduction for the reasonable actual costs incurred by the lessee to transport unprocessed gas, residue gas, and gas plant products from a lease to a point off the lease including, if appropriate, transportation from the lease to a gas processing plant off the lease and from the plant to a point away from the plant.

(b) Transportation costs must be allocated among all products produced and transported as provided in § 206.157.

(c)(1) Except as provided in paragraph (c)(3) of this section, for unprocessed gas valued in accordance with § 206.152 of this subpart, the transportation allowance deduction on the basis of a selling arrangement shall not exceed 50 percent of the value of the unprocessed gas determined in accordance with § 206.152 of this subpart.

(2) Except as provided in paragraph (c)(3) of this section, for gas production valued in accordance with § 206.153 of this subpart the transportation

allowance deduction on the basis of a selling arrangement shall not exceed 50 percent of the value of the residue gas or gas plant product determined in accordance with § 206.153 of this subpart. For purposes of this section, natural gas liquids shall be considered one product.

(3) Upon request of a lessee, MMS may approve a transportation allowance deduction in excess of the limitations prescribed by paragraphs (c)(1) and (c)(2) of this section. The lessee must demonstrate that the transportation costs incurred in excess of the limitations prescribed in paragraphs (c)(1) and (c)(2) of this section were reasonable, actual, and necessary. An application for exception shall contain all relevant and supporting documentation necessary for the MMS to make a determination. Under no circumstances shall the value for royalty purposes under any selling arrangement be reduced to zero.

(d) If, after a review and/or audit, MMS determines that a lessee has improperly determined a transportation allowance authorized by this subpart, then the lessee shall pay any additional royalties, plus interest, determined in accordance with 30 CFR 218.54, or shall be entitled to a credit, without interest.

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30 C.F.R. § 206.157 (1994):

§ 206.157 Determination of transportation allowances.

(a) *Arm's-length transportation contracts.* (1)(i) For transportation costs incurred by a lessee pursuant to an arm's-length contract, the transportation allowance shall be the reasonable, actual costs incurred by the lessee for transporting the unprocessed gas, residue gas and/or gas plant products under that contract, except as provided in paragraphs (a)(1) (ii) and (iii) of this section, subject to monitoring, review, audit, and adjustment. The lessee shall have the burden of demonstrating that its contract is arm's-length. Such allowances shall be subject to the provisions of paragraph (f) of this section. Before any deduction may be taken, the lessee must submit a completed page one of Form MMS-4295 (and Schedule 1). Gas Transportation Allowance Report in accordance with paragraph (c)(1) of this section. A transportation allowance may be claimed retroactively for a period of not more than 3 months prior to the first day of the month that Form MMS-4295 is filed with MMS, unless MMS approves a longer period upon a showing of good cause by the lessee.

(ii) In conducting reviews and audits, MMS will examine whether or not the contract reflects more than the consideration actually transferred either directly or indirectly from the lessee to the

transporter for the transportation. If the contract reflects more than the total consideration, then the MMS may require that the transportation allowance be determined in accordance with paragraph (b) of this section.

(iii) If the MMS determines that the consideration paid pursuant to an arm's-length transportation contract does not reflect the reasonable value of the transportation because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS shall require that the transportation allowance be determined in accordance with paragraph (b) of this section. When MMS determines that the value of the transportation may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's transportation costs.

(2)(i) If an arm's-length transportation contract includes more than one product in a gaseous phase and the transportation costs attributable to each product cannot be determined from the contract, the total transportation costs shall be allocated in a consistent and equitable manner to each of the products transported in the same proportion as the ratio of the volume of each product (excluding waste products which have no

value) to the volume of all products in the gaseous phase (excluding waste products which have no value). Except as provided in this paragraph, no allowance may be taken for the costs of transporting lease production which is not royalty bearing without MMS approval.

(ii) Notwithstanding the requirements of paragraph (i), the lessee may propose to MMS a cost allocation method on the basis of the values of the products transported. MMS shall approve the method unless it determines that it is not consistent with the purposes of the regulations in this part.

(3) If an arm's-length transportation contract includes both gaseous and liquid products and the transportation costs attributable to each cannot be determined from the contract, the lessee shall propose an allocation procedure to MMS. The lessee may use the transportation allowance determined in accordance with its proposed allocation procedure until MMS issues its determination on the acceptability of the cost allocation. The lessee shall submit all relevant data to support its proposal. The initial proposal must be submitted by June 30, 1988, or within 3 months after the last day of the month for which the lessee requests a transportation allowance, whichever is later (unless MMS approves a longer period). The MMS shall then determine the gas transportation allowance based upon the lessee's proposal and any additional information MMS deems necessary.

(4) Where the lessee's payments for transportation under an arm's-length contract are not based on a dollar per unit, the lessee shall convert whatever consideration is paid to a dollar value equivalent for the purposes of this section.

(5) Where an arm's-length sales contract price or a posted price includes a provision whereby the listed price is reduced by a transportation factor, MMS will not consider the transportation factor to be a transportation allowance. The transportation factor may be used in determining the lessee's gross proceeds for the sale of the product. The transportation factor may not exceed 50 percent of the base price of the product without MMS approval.

(b) *Non-arm's-length or no contract.* (1) If a lessee has a non-arm's-length transportation contract or has no contract, including those situations where the lessee performs transportation services for itself, the transportation allowance will be based upon the lessee's reasonable actual costs as provided in this paragraph. All transportation allowances deducted under a non-arm's-length or no contract situation are subject to monitoring, review, audit, and adjustment. Before any estimated or actual deduction may be taken, the lessee must submit a completed Form MMS-4295 in accordance with paragraph (c)(2) of this section. A transportation allowance may be claimed retroactively for a period of not more than 3 months prior to the first day of the month that Form MMS-4295 is filed with MMS, unless

MMS approves a longer period upon a showing of good cause by the lessee. The MMS will monitor the allowance deductions to ensure that deductions are reasonable and allowable. When necessary or appropriate, MMS may direct a lessee to modify its estimated or actual transportation allowance deduction.

(2) The transportation allowance for non-arm's-length or no-contract situations shall be based upon the lessee's actual costs for transportation during the reporting period, including operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment in accordance with paragraph (b)(2)(iv)(A) of this section, or a cost equal to the initial depreciable investment in the transportation system multiplied by a rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those costs for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the transportation system.

(i) Allowable operating expenses include: Operations supervision and engineering; operations labor; fuel; utilities; materials; ad valorem property taxes; rent; supplies; and any other directly allocable and attributable operating expense which the lessee can document.

(ii) Allowable maintenance expenses include: Maintenance of the transportation system; maintenance of equipment; maintenance labor; and other directly allocable and attributable maintenance expenses which the lessee can document.

(iii) Overhead directly attributable and allocable to the operation and maintenance of the transportation system is an allowable expense. State and Federal income taxes and severance taxes and other fees, including royalties, are not allowable expenses.

(iv) A lessee may use either depreciation or a return on depreciable capital investment. After a lessee has elected to use either method for a transportation system, the lessee may not later elect to change to the other alternative without approval of the MMS.

(A) To compute depreciation, the lessee may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the transportation system services, or a unit of production method. After an election is made, the lessee may not change methods without MMS approval. A change in ownership of a transportation system shall not alter the depreciation schedule established by the original transporter/lessee for purposes of the allowance calculation. With or without a change

in ownership, a transportation system shall be depreciated only once. Equipment shall not be depreciated below a reasonable salvage value.

(B) The MMS shall allow as a cost an amount equal to the allowable initial capital investment in the transportation system multiplied by the rate of return determined pursuant to paragraph (b)(2)(v) of this section. No allowance shall be provided for depreciation. This alternative shall apply only to transportation facilities first placed in service after March 1, 1988.

(v) The rate of return shall be the industrial rate associated with Standard and Poor's BBB rating. The rate of return shall be the monthly average rate as published in *Standard and Poor's Bond Guide* for the first month of the reporting period for which the allowance is applicable and shall be effective during the reporting period. The rate shall be redetermined at the beginning of each subsequent transportation allowance reporting period (which is determined pursuant to paragraph (c) of this section).

(3)(i) The deduction for transportation costs shall be determined on the basis of the lessee's cost of transporting each product through each individual transportation system. Where more than one product in a gaseous phase is transported, the allocation of costs to each of the products transported shall be made in a consistent and equitable manner in the same proportion as the ratio of the volume of each

product (excluding waste products which have no value) to the volume of all products in the gaseous phase (excluding waste products which have no value). Except as provided in this paragraph, the lessee may not take an allowance for transporting a product which is not royalty bearing without MMS approval.

(ii) Notwithstanding the requirements of paragraph (b)(3)(i), the lessee may propose to the MMS a cost allocation method on the basis of the values of the products transported. MMS shall approve the method unless it determines that it is not consistent with the purposes of the regulations in this part.

(4) Where both gaseous and liquid products are transported through the same transportation system, the lessee shall propose a cost allocation procedure to MMS. The lessee may use the transportation allowance determined in accordance with its proposed allocation procedure until MMS issues its determination on the acceptability of the cost allocation. The lessee shall submit all relevant data to support its proposal. The initial proposal must be submitted by June 30, 1988 or within 3 months after the last day of the month for which the lessee begins the transportation, whichever is later, unless MMS approves a longer period. The MMS shall then determine the transportation allowance based upon the lessee's proposal and any additional information MMS deems necessary.

(5) A lessee may apply to the MMS for an exception from the requirement that it compute actual costs in accordance with paragraphs (b)(1) through (b)(4) of this section. The MMS will grant the exception only if the lessee has a tariff for the transportation system approved by the Federal Energy Regulatory Commission (FERC) (for both Federal and Indian leases) or a State regulatory agency (for Federal leases). The MMS shall deny the exception request if it determines that the tariff is excessive as compared to arm's-length transportation charges by pipelines, owned by the lessee or others, providing similar transportation services in that area. If there are no arm's-length transportation charges, MMS shall deny the exception request if: (i) No FERC or State regulatory agency cost analysis exists and the FERC or State regulatory agency, as applicable, has declined to investigate pursuant to MMS timely objections upon filing; and (ii) the tariff significantly exceeds the lessee's actual costs for transportation as determined under this section.

(c) *Reporting requirements* — (1) *Arm's-length contracts.* (i) With the exception of those transportation allowances specified in paragraphs (c)(1) (v) and (vi) of this section, the lessee shall submit page one of the initial Form MMS-4295 (and Schedule 1) prior to, or at the same time as, the transportation allowance determined pursuant to an arm's-length contract is reported on Form MMS-2014, Report of Sales and Royalty

Remittance. A Form MMS-4295 received by the end of the month that the Form MMS-2014 is due shall be considered to be timely received.

(ii) The initial Form MMS-4295 shall be effective for a reporting period beginning the month that the lessee is first authorized to deduct a transportation allowance and shall continue until the end of the calendar year, or until the applicable contract or rate terminates or is modified or amended, whichever is earlier.

(iii) After the initial reporting period and for succeeding reporting periods, lessees must submit page one of Form MMS-4295 (and Schedule 1) within 3 months after the end of the calendar year, or after the applicable contract or rate terminates or is modified or amended, whichever is earlier, unless MMS approves a longer period (during which period the lessee shall continue to use the allowance from the previous reporting period).

(iv) The MMS may require that a lessee submit arm's-length transportation contracts, production agreements, operating agreements, and related documents. Documents shall be submitted within a reasonable time, as determined by MMS.

(v) Transportation allowances which are based on arm's-length contracts and which are in effect at the time these regulations become effective will be allowed to continue until such

allowances terminate. For the purposes of this section, only those allowances that have been approved by MMS in writing shall qualify as being in effect at the time these regulations become effective.

(vi) The MMS may establish, in appropriate circumstances, reporting requirements which are different from the requirements of this section.

(2) *Non-arm's-length or no contract.* (i) With the exception of those transportation allowances specified in paragraphs (c)(2) (v), (vii), and (viii) of this section, the lessee shall submit an initial Form MMS-4295 prior to, or at the same time as, the transportation allowance determined pursuant to a non-arm's-length contract or no-contract situation is reported on Form MMS-2014, Report of Sales and Royalty Remittance. A Form MMS-4295 received by the end of the month that the Form MMS-2014 is due shall be considered to be timely received. The initial report may be based upon estimated costs.

(ii) The initial Form MMS-4295 shall be effective for a reporting period beginning the month that the lessee first is authorized to deduct a transportation allowance and shall continue until the end of the calendar year, or until the transportation under the non-arm's-length contract or the no contract situation terminates, whichever is earlier.

(iii) For calendar-year reporting periods succeeding the initial reporting period, the lessee shall submit a completed Form MMS-4295 containing the actual costs for the previous reporting period. If the transportation is continuing, the lessee shall include on Form MMS-4295 its estimated costs for the next calendar year. The estimated transportation allowance shall be based on the actual costs for the previous reporting period plus or minus any adjustments which are based on the lessee's knowledge of decreases or increases which will affect the allowance. Form MMS-4295 must be received by MMS within 3 months after the end of the previous reporting period, unless MMS approves a longer period (during which period the lessee shall continue to use the allowance from the previous reporting period).

(iv) For new transportation facilities or arrangements, the lessee's initial Form MMS-4295 shall include estimates of the allowable transportation costs for the applicable period. Cost estimates shall be based upon the most recently available operations data for the transportation system, or if such data are not available, the lessee shall use estimates based upon industry data for similar transportation systems.

(v) Non-arm's-length contract or no contract based transportation allowances which are in effect at the time these regulations become

effective will be allowed to continue until such allowances terminate. For the purposes of this section, only those allowances that have been approved by MMS in writing shall qualify as being in effect at the time these regulations become effective.

(vi) Upon request by MMS, the lessee shall submit all data used to prepare its Form MMS-4295. The data shall be provided within a reasonable period of time, as determined by MMS.

(vii) The MMS may establish in appropriate circumstances, reporting requirements which are different from the requirements of this section.

(viii) If the lessee is authorized to use its FERC-approved or State regulatory agency-approved tariff as its transportation cost in accordance with paragraph (b)(5) of this section, it shall follow the reporting requirements of paragraph (c)(1) of this section.

(3) The MMS may establish reporting dates for individual lessees different than those specified in this subpart in order to provide more effective administration. Lessees will be notified of any change in their reporting period.

(4) Transportation allowances must be reported as a separate line item on Form MMS-2014, unless MMS approves a different reporting procedure.

(d) *Interest assessments for incorrect or late reports and failure to report.* (1) If a lessee deducts a transportation allowance on its Form MMS-2014 without complying with the requirements of this section, the lessee shall pay interest only on the amount of such deduction until the requirements of this section are complied with. The lessee also shall repay the amount of any allowance which is disallowed by this section.

(2) If a lessee erroneously reports a transportation allowance which results in an underpayment of royalties, interest shall be paid on the amount of that underpayment.

(3) Interest required to be paid by this section shall be determined in accordance with 30 CFR 218.54.

(e) *Adjustments.* (1) If the actual transportation allowance is less than the amount the lessee has taken on Form MMS-2014 for each month during the allowance form reporting period, the lessee shall be required to pay additional royalties due plus interest computed pursuant to 30 CFR 218.54, retroactive to the first day of the first month the lessee is authorized to deduct a transportation allowance. If the actual transportation allowance is greater than the amount the lessee has taken on Form MMS-2014 for each month during the allowance form reporting period, the lessee shall be entitled to a credit without interest.

(2) For lessees transporting production from onshore Federal and Indian leases, the lessee must submit a corrected Form MMS-2014 to reflect actual costs, together with any payment, in accordance with instructions provided by MMS.

(3) For lessees transporting gas production from leases on the OCS, if the lessee's estimated transportation allowance exceeds the allowance based on actual costs, the lessee must submit a corrected Form MMS-2014 to reflect actual costs, together with its payment, in accordance with instructions provided by MMS. If the lessee's estimated transportation allowance is less than the allowance based on actual costs, the refund procedure will be specified by MMS.

(f) *Actual or theoretical losses.* Notwithstanding any other provisions of this subpart, for other than arm's-length contracts no cost shall be allowed for transportation which results from payments (either volumetric or for value) for actual or theoretical losses. This section does not apply when the transportation allowance is based upon FERC or state regulatory agency approved tariff.

(g) *Other transportation cost determinations.* The provisions of this section shall apply to determine transportation costs when establishing value using a net-back valuation procedure or any other procedure that requires deduction of transportation costs.

* * * *

APPENDIX H — OTHER RELATED MATERIAL

[Omitted here but submitted separately as Lodging]